Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

Robert A. Alm
Executive Vice President
Public Affairs

January 30, 2009

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
Kekuanaoa Building, 1st Floor
465 South King Street
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 2008-0274 – Decoupling Proceeding
<u>The HECO Companies' Revenue Decoupling Proposal</u>

In accordance with the *Order Approving, with Modifications, Stipulated Procedural Order Filed on December 26, 2008*, issued by the Commission on January 21, 2009, enclosed for filing is the Revenue Decoupling Proposal of Hawaiian Electric Company, Inc. ("HECO"), Hawaii Electric Light Company, Inc., ("HELCO"), and Maui Electric Company, Limited ("MECO") (collectively, the "HECO Companies"). The HECO Companies have worked with their consultant, Pacific Economics Group, LLC ("PEG") to develop a Decoupling Mechanism consistent with the mechanism agreed to in the landmark *Energy Agreement among the State of Hawaii, Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs, and the Hawaiian Electric Companies* ("HCEI Agreement").[1]

The HCEI Agreement acknowledges that the signatories of the agreement must "move more decisively and irreversibly away from imported fossil fuel for electricity and transportation and towards indigenously produced renewable energy and an ethic of energy efficiency." In addition to memorializing the commitment by the signatories to support the acceleration to a much more renewable, distributed and intermittent-powered system with a smart grid, the signatories also recognize the "need

[1] On October 20, 2008, the Governor of the State of Hawaii, the State of Hawaii Department of Business, Economic Development and Tourism, the Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs ("Consumer Advocate") and the HECO Companies executed the HCEI Agreement.

to assure that Hawaii preserves a stable electric grid to minimize disruption to service quality and reliability. In addition, we recognize the need for a financially sound electric utility. Both are vital components for our achievement of an independent renewable energy future." Thus, the HCEI Agreement also acknowledged the need for the HECO Companies to be compensated under a regulatory model that removes barriers to supporting such a future and still provides for financially sound utilities that retain their obligation to serve the public with reliable energy.

The Decoupling Mechanism includes a Sales Decoupling Mechanism and a Revenue Adjustment Mechanism. The purpose of the Sales Decoupling mechanism is to remove the linkage between utility sales and revenues, in order to encourage energy efficiency. The purpose of the Revenue Adjustment Mechanism is to adjust revenues decoupled from sales to reflect changes in revenue requirements between rate cases, in order to help maintain the utility's financial integrity and ability to invest in the infrastructure necessary to meet Hawaii's 70% clean energy objective, while maintaining reliable service to customers.

As the HCEI Agreement recognizes, utility costs and the need to make investments in infrastructure are likely to increase each year. Under traditional ratemaking sales increases between rate cases provided the utility an opportunity to recover the associated cost increases. However, setting a target revenue requirement that does not change between rate cases under sales decoupling provides no compensation to the utility for increases in utility costs or infrastructure investments. Therefore, there is a need to allow increases in the target revenue requirement level each year. This is accomplished through the revenue adjustment mechanism, or "RAM".

The Decoupling Mechanism proposal is preliminary, and is intended to facilitate discussion. The HECO Companies may refine their Decoupling Mechanism proposal in their Initial Statement of Position to be submitted March 30, 2009, along with the proposals of the other parties, in order to take into account the information shared by the Parties at workshops on April 20-21, 2009, and through responses to information requests.

The representatives of the HECO Companies and PEG (by phone) met with the representatives of the Division of Consumer Advocacy (the "Consumer Advocate") and its consultant, Utilitech, Inc. over two days on December 16 and 17, 2008 to discuss decoupling concepts and implementation mechanisms. The HECO Companies provided a preliminary draft of this proposal to the Consumer Advocate on January 20, 2009, provided earlier drafts of the PEG report on November 25, 2008 and

December 2, 2008, and responded to informal requests for information to facilitate the discussion over the period from December 1, 2008 through January 8, 2009.

The HECO Companies appreciate the extensive participation of the Consumer Advocate, and comments and questions provided by Utilitech have helped the HECO Companies considerably in formulating their preliminary proposal. Thus, while the HECO Companies and the Consumer Advocate are separately submitting preliminary proposals to facilitate the Commission's review of decoupling in this docket, the HECO Companies hope to continue their discussions with the Consumer Advocate, while considering the proposals and perspectives brought to this proceedings by the other Parties as well.

Very truly yours,

Robert A. Alm
Executive Vice President

Enclosures

cc: Division of Consumer Advocacy
Life of the Land
Hawaii Renewable Energy Alliance
Haiku Design and Analysis
Hawaii Holdings, LLC dba First Wind Hawaii
Department of Business, Economic Development, and Tourism
Hawaii Solar Energy Association
Blue Planet Foundation

REVENUE DECOUPLING PROPOSAL
OF THE HAWAIIAN ELECTRIC COMPANIES

POLICY CONSIDERATIONS

Hawaii's geographic isolation in the middle of the Pacific Ocean places a premium on energy self-sufficiency and sustainability. The state currently depends heavily on oil imported from foreign destinations to drive its economy, sustain the standard of living, and serve the needs of its citizens. Thus, risk to energy security is another major challenge to overcome.

However, significant initiatives to overcome these challenges have been started. Major strides to increase energy conservation and improve energy efficiency have been evident in recent years that have led to reductions in energy demand. Furthermore, promising supply technologies such as customer-sited photovoltaic generation are becoming economically feasible and, therefore, more popular among utility customers.

Community stakeholders, government, and the utilities agree that more needs to be done to support increased efforts to make Hawaii energy self-sufficient, improve its energy sustainability, and reduce risks to energy security. The landmark *Energy Agreement Among the State of Hawaii, Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs, and the Hawaiian Electric Companies* ("HCEI Agreement") acknowledges that the signatories of the agreement must "move more decisively and irreversibly away from imported fossil fuel for electricity and transportation and towards indigenously produced renewable energy and an ethic of energy efficiency."

In addition, "[W]e recognize the need to assure that Hawaii preserves a stable electric grid to minimize disruption to service quality and reliability. In addition, we recognize the need for a financially sound electric utility. Both are vital components for our achievement of an independent renewable energy future."

However, traditional utility ratemaking contains a disincentive to energy efficiency and customer sited renewable energy that may restrain electric utility efforts to fully support these initiatives. The revenue decoupling proposal of Hawaiian Electric Company, Inc., Maui Electric Company, Ltd, and Hawaii Electric Light Company, Inc. ("The HECO Companies or Companies") is designed to overcome this disincentive that is inherent under traditional "price cap" ratemaking (where prices are fixed in rate cases, and revenues vary with sales).

The disincentive stems from the manner in which utilities operating under traditional ratemaking recover their fixed costs. Typically, utilities (like the HECO Companies) recover their fixed costs partially through fixed charges, such as customer charges, and partially through volumetric charges such as energy (or per kilowatthour) charges. This rate design works well when kilowatthour sales increase from year to year. The increase in sales increases revenues to cover the fixed costs approved by regulators in the last rate case and also compensates the utility for, 1) cost escalation due to needed expansion of system infrastructure, service volumes, and, of course, inflation, and 2) maintaining an adequate return on rate base to attract investors.

However, if sales are stagnant or are on a long-term decreasing trend, the falling revenues fail to fully recover fixed costs. This leads to an erosion of utility earnings and financial performance, and a reduction in the utility's capacity to invest in needed infrastructure to support reliability and public policy priorities such as renewable energy. Under traditional ratemaking the conventional solution to this situation is to initiate a rate case. However, since rate proceedings take, usually, at the very least, many months to adjudicate, it is difficult for the utility to maintain financial health. Under these conditions, it is not unusual for utilities to need to file for rate cases in quick succession in an effort to reset their rates to compensate for falling sales and increasing costs.

Conservation, energy efficiency, and customer-sited renewable generation contribute to falling sales. While these measures move the state toward energy goals that all stakeholders support, the erosion of electricity sales and revenues results in significant negative financial impacts to the utilities. If the utilities' revenues were not linked to sales, the disincentive to conservation, energy efficiency, and renewable generation could be eliminated. The HECO Companies' revenue decoupling proposal removes that disincentive.

HAWAII CLEAN ENERGY INITIATIVE ("HCEI") AGREEMENT

On October 20, 2008, the Governor of the State of Hawaii, the State of Hawaii Department of Business, Economic Development and Tourism, the Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs ("Consumer Advocate") and the HECO Companies executed an energy agreement resulting from the HCEI Agreement to move Hawaii away from imported fossil fuel for electricity and transportation and towards locally produced renewable energy and an ethic of energy efficiency. Besides memorializing the commitment by the signatories to support the acceleration to a much more renewable, distributed and intermittent-powered system with a smart grid, the HCEI Agreement also acknowledged the need for the HECO Companies to be compensated under a regulatory model that removes barriers to supporting such a future and still provides for financially sound utilities that retain their obligation to serve the public with reliable energy. In section 28, "Decoupling from Sales", of the HCEI Agreement, the signatories agreed to a decoupling mechanism that separates ("decouples") the HECO Companies' revenues from energy sales. Section 28 states:

"...The parties agree in principle that it is appropriate to adopt a decoupling mechanism that closely tracks the mechanisms in place for several California electric utilities, as follows:

> 1. The revenues of the utility will be fully decoupled from sales/revenues beginning with the interim decision in the 2009 Hawaiian Electric Company Rate Case (most likely in the summer of 2009).
>
> The utility will use a revenue adjustment mechanism based on cost tracking indices such as those used by the California regulators for their larger utilities or its equivalent and not based on customer count. Such a decoupling mechanism would, on an ongoing basis, provide revenue adjustments for the differences between the amount determined in the last rate case and:
>
> (a) The current cost of operating the utility that is deemed reasonable and approved by the PUC;
>
> (b) Return on and return of ongoing capital investment (excluding those projects included in the Clean Energy Infrastructure Surcharge); and
>
> (c) Any changes in State or federal tax rates.
>
> Adjustments shall occur on a quarterly basis, semi-annual, or annual based or the availability of the indices utilized. The adjustments will continue until such time that they are incorporated in the utility's base rates.
>
> 2. The parties agree that the decoupling mechanism that will be implemented will be subject to review and approval by the PUC.
>
> 3. The utility will continue to use tracking mechanisms for Commission-approved pension and other post-retirement benefits to ensure that the expenses are evened out for the ratepayer and are not subject to sudden and dramatic swing.

4. The Commission may review the decoupling mechanism at any time if it determines that the mechanism is not operating in the interests of the ratepayers.

5. The utility or the Consumer Advocate may also file a request to review the impact of the decoupling mechanism.

6. The Commission may unilaterally discontinue the decoupling mechanism if it finds that the public interest requires such action.

7. In order to implement the decoupling mechanism, the parties agree that HELCO and MECO will file for a 2009 test year rate case."

Item number 1. above refers to the two components of revenue decoupling: a sales decoupling mechanism and a revenue adjustment mechanism.

Because the HCEI Agreement envisions that the revenues of HECO would be decoupled from sales beginning with the interim decision in the 2009 test year HECO rate case, Docket No. 2008-0083, the Public Utilities Commission of the State of Hawaii ("Commission") opened Docket No. 2008-0274 ("Decoupling Docket") in its Order Initiating Investigation ("Order"), issued October 24, 2008. On page 9 of the Order, the Commission ordered the Companies and the Consumer Advocate to submit a joint proposal on decoupling that addresses all of the factors identified in the HCEI Agreement by December 23, 2008. On December 3, 2008, the Commission issued an order in the Decoupling Docket which granted intervention to seven different parties ("Intervenors") and also extended the date to submit a joint decoupling proposal from December 23, 2008, to February 17, 2009 (page 12). On December 26, 2008, the Companies, the Consumer Advocate, and the Intervenors filed a stipulated procedural order for the docket which reflected a filing date of January 30, 2009, for the decoupling proposal(s) by the Companies and the Consumer Advocate. The stipulated procedural order was approved by the Commission on January 15, 2009, with modifications.

REVENUE DECOUPLING PROPOSAL

The HECO Companies' revenue decoupling proposal is an automatic rate adjustment clause that contains two mechanisms consistent with the HCEI Agreement:

1. Sales decoupling, which breaks the link between sales and electric revenue
2. Revenue adjustment mechanism ("RAM")

Under sales decoupling electric revenue is not a function of sales. Instead, a target revenue requirement is set through a rate proceeding and the utility is allowed to adjust its rates between rate cases to meet that revenue requirement. The revenue requirement excludes fuel and purchased power (and any other) expenses that are recovered outside of base rates. However, the setting of a target revenue requirement does not guarantee the utility a certain level of profit. Instead, the utility must still manage its expenditures to provide reliable electrical service to its customers.

Sales decoupling requires that there be a process to capture the difference between the target revenue requirement and billed revenues collected, and to adjust rate levels (through an adjustment clause) to make up the difference. The HECO Companies propose to establish a Revenue Balancing Account ("RBA") to facilitate that process. Details of the RBA can be found later in this proposal.

As indicated above, utility costs and the need to make investments in infrastructure are likely to increase each year. Under traditional ratemaking sales increases between rate cases provided the utility an opportunity to recover the associated cost increases. However, setting a target revenue requirement that does not change between rate cases under sales decoupling provides no compensation to the utility for increases in utility costs or infrastructure investments. Therefore, there is a need to allow increases in the target revenue requirement level each year. This is accomplished through a revenue adjustment mechanism, or RAM.

There are many forms of RAMs. Dr. Mark Lowry, of Pacific Economics Group, LLC ("PEG") discusses these forms in the accompanying report (Attachment 1), *Revenue Decoupling for Hawaiian Electric Companies*. The HECO Companies propose a hybrid RAM, in which operations and maintenance ("O&M") expenses are escalated using a formula that includes inflation or input cost escalators (a formulaic approach), and rate base is escalated based on a trended forecast. The term "hybrid" refers to the combination of formulaic and forecast approaches to derive the annual change in target revenue requirements.

The accompanying PEG report also identifies the arguments for and against revenue decoupling. HECO maintains that the benefits outweigh the arguments against decoupling.

This filing contains the proposal developed by the HECO Companies to implement revenue decoupling and the factors and provisions identified in the HCEI Agreement. All calculations, tables, and attachments in this preliminary proposal are estimates or trended numbers only, and are not to be construed as forward-looking financial information or forecasts by the Companies. These preliminary calculations, tables, and attachments are also subject to change as the Companies continue to review these analyses.

As explained earlier, the HCEI Agreement identifies two mechanisms that together combine to implement decoupling from sales: 1) sales decoupling; and 2) the revenue adjustment mechanism (a mechanism to adjust utility rates for trends in input prices, demand, and other external business conditions that affect utility earnings).

Sales Decoupling

The HECO Companies' proposal regarding the implementation and timing of the sales decoupling mechanism is based on the cycle that is prescribed for Southern California Edison Company.[1] The HECO Companies propose that the initial sales decoupling mechanism begin with the establishment of interim target revenues, i.e., revenue requirements approved by the Commission in its interim decision and orders for each of the Companies' 2009 test year general rate case proceedings. The revenue requirements will be based on traditional cost-of-service ratemaking principles for each of the individual HECO Companies.

The Companies propose the establishment of revenue balancing accounts ("RBAs") to record the monthly differences between the approved interim revenue requirement for electric sales revenues[2] in their 2009 test year rate cases and the electric sales revenues recorded (the comparison will be made with revenues for fuel and purchased power expenses removed). In its 2009 test year rate case (Docket No. 2008-0083), Rate Case Update, HECO T-1, pages 8-11, HECO has proposed the establishment of an RBA to be implemented upon the issuance of an interim order by the Commission. A detailed description of the RBA, which was included in the Rate Case Update, is submitted as Attachment 2 to this proposal.

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[1] The timing for the implementation of the revenue adjustment mechanism adjustment to rates is described later in this proposal.

[2] The allocation of the revenue requirements to the remaining months in the year will be specified in the Companies' tariffs. The allocation will be based on the mWh sales forecast during the period that the target revenue requirement remains in effect.

The HECO Companies propose that separate target revenue requirements be established for residential customers and for a single collective group of commercial (including industrial) customers. Each of the HECO Companies would employ separate RBAs for residential customers and for commercial customers. For the purpose of calculating the monthly difference to record to the RBAs, recorded electric sales revenue includes revenue from regular and optional rate schedule charges plus revenue from any interim rate increase adjustments that are in effect.

As explained in Attachment 2, besides reflecting the accumulated monthly differences, the RBA will also reflect the accrual of interest at a rate equal to the then-approved rate of return applied to the simple average of the beginning and ending monthly balances. Upon the issuance of the final decision and orders in the 2009 test year rate cases, the RBA would begin to accumulate the monthly differences between the recorded sales revenues and the final approved target revenues (the comparison will be made with revenues for fuel and purchased power expenses removed).

The estimated amounts in the year-end RBA balances will be cleared to customers in an RBA rate adjustment over the 12 months of the succeeding calendar year if the balance is greater than some threshold level. The establishment of the threshold is to avoid unnecessarily changing customer charges if the change is not material for that period. In November of each year, the Companies will notify the Commission of the estimated RBA year-end balances (based on the estimated October 31 balances and the forecasted charges/credits to the RBAs, including interest for November and December of that year). If the RBA balance meets or exceeds the threshold, the Companies will propose separate per kWh RBA rate adjustments, one for the residential customer RBA and one for the commercial customer RBA, that will apply over the next calendar year, that will collect/refund the expected RBA current year-end balance, based on the next calendar year's expected kWh sales. The revenue from the RBA rate adjustments will be included in the recorded electric revenue that is compared to the revenue requirement targets for the calculation of the monthly differences to be added to the RBAs.

If the threshold is not met, the RBA balance would be held and carried over to following year's RBA adjustment.

Practically speaking, the above described timeline will only apply to HECO in 2009 since MECO and HELCO have not yet filed their 2009 test year general rate cases and the Companies anticipate that the interim decision and orders for these rate cases will not be issued until 2010. The RBAs for MECO and HELCO will be established at that time and the same procedure as described above for HECO will apply.

Like Southern California Edison Company, the HECO Companies propose a three-year sales decoupling cycle, i.e., where rate cases are filed for test years that are three years apart[3]. However, because the three HECO Companies will all have the same starting test year for the rate case cycles and are supported by the same regulatory department and the same witnesses for certain testimonies, in order to minimize the need for resources and be able to submit rate case filings of the highest quality possible in the future, the HECO Companies propose to stagger the rate cases after the 2009 test year and commence the three-year rate case cycles thereafter. This will result in the filing of

[3] At the request of the HECO Companies, the Pacific Economics Group, LLC, performed a study that analyzed three- and four-year cycles. The three-year cycles were found to be less compensatory to HECO while more compensatory for MECO and HELCO (see Attachment 1, Table 10-Financial Sufficiency Simulation: Summary of All Plans, of PEG's "Revenue Decoupling for Hawaiian Electric Companies" report]). However, because of the rapidity of economic and political changes experienced in recent times, the Companies concluded that a three-year cycle would be prudent as it would allow the HECO Companies, the Commission, and the Consumer Advocate to reset the revenue requirement (i.e., target revenues) and review, analyze, and change the decoupling and RAM mechanisms if needed in a more timely manner.

only one rate case per year after the initial round of 2009 test year rate cases. Hence, the scheduling of the next round of rate cases would be as follows:

Company	Year of Filing	Test Year
HECO	2010	2011
MECO/HELCO	2011	2012
MECO/HELCO	2012	2013

The ability of HECO to refrain from filing a 2010 test year rate proceeding and wait until 2011 for its next rate case will depend on the award issued for its 2009 test year rate case and the outcome of this Decoupling Docket. Should HECO determine that a 2010 rate case filing is necessary, the HECO Companies will revisit the timing and starting point for the proposed 3-year general rate case cycle.

Revenue Adjustment Mechanism ("RAM")

As stated earlier, utility costs and the need to make investments in infrastructure are likely to increase each year. Under traditional ratemaking sales increases between rate cases provided the utility an opportunity to recover the associated cost increases. However, setting a target revenue requirement that does not change between rate cases under sales decoupling provides no compensation to the utility for increases in utility costs or infrastructure investments. Therefore, there is a need to allow increases in the target revenue requirement level each year. This is accomplished through a revenue adjustment mechanism, or RAM.

The Companies' proposed RAM will enable revenue adjustments between rate cases to the individual Companies' test year revenue requirements for changes in input prices for O&M expenses and capital requirements in the future. Based on results of studies that are discussed below, the HECO Companies propose that the RAM adjustment for post-test years be based on a hybrid model, i.e., the methodology to calculate the change in O&M expenses is formulaic and differs from the forecast methodology that is used to calculate the change in rate base.

Specifically, the Companies' current preference is that the O&M RAM escalate O&M labor and nonlabor expense components by the growth in forecasted utility cost indices from Global Insight, Inc. ("Global Insight") and that the rate base RAM escalate rate base by the HECO Companies' individual historical trended growth in rate base plus significant plant additions from their capital budget forecast.

The hybrid RAM is just one of a number of RAMs that could have been selected for further discussion. However, the hybrid RAM is the only mechanism that meets the HCEI Agreement criteria, which includes a mechanism based on cost tracking indices such as those used by the California regulators, not based on customer count, and providing revenue adjustments for the differences between the amount determined in the last rate case and the current cost of operating the utility and the return on and return of ongoing capital investment. Nevertheless, HECO requested that PEG explore all significant forms of RAM including:

- Revenue per Customer ("RPC") freeze,
- Inflation Relief Only,
- RPC Index,
- All Forecast, and
- Hybrid used by SCE

PEG was asked to: 1) review and survey the various RAMs that have been and are in use by other utilities, particularly including those used by the California electric utilities; 2) simulate the financial impact of these alternative RAMs for HECO, HELCO, and MECO over a recent historical period of 1996 through 2007 to determine whether such RAM alternatives would provide the individual companies with sufficient financial resources;[4] 3) determine the impact of different rate case cycle intervals on the individual companies' financial sufficiency; 4) recommend specific indices to be considered by the HECO Companies in their hybrid RAM proposal; and 5) simulate the financial impact of these specific indices to determine the financial sufficiency provided to the individual HECO Companies. PEG's report, *Revenue Decoupling for Hawaiian Electric Companies Revenue Decoupling for Hawaiian Electric Companies* is attached as Attachment 1.

RAM Calculation for O&M Expenses

The financial sufficiency simulations conducted by PEG provided hypothetical impacts on revenue requirements over the historical period 1996 through 2007. This is a 12-year period and allows either a 3-year or 4-year general rate case cycle to use all of the available years. For a 3-year assumed rate case cycle, rates were assumed to be reset every third year (the base years) to provide sufficient revenues at the allowed rate of return on rate base. Between assumed rate cases, 1) the O&M RAM was applied to the base year O&M costs, 2) the actual rate base for the year was assumed to be the authorized rate base, and 3) the target revenue requirement was assumed to provide the allowed rate of return on rate base. The target revenue requirement was then compared

[4] O&M Costs used in the simulations excluded all pension, fuel, purchased power, DSM and IRP costs, and associated revenue taxes since these costs will not be recovered through base rates but through various trackers and individual surcharges. Depreciation expense was also not included as changes in depreciation expense is a function of the rate base revenue adjustment mechanism and accounted for in the rate base RAM.

to a simulated revenue requirement calculated as above but using actual O&M costs rather than O&M costs derived using the RAM.

PEG expressed the comparison in two ways: the average difference in revenue requirement dollars and in a ratio of the average target revenue requirement versus the simulated revenue requirement. Since the only difference between the two annual revenue requirement calculations was the application of the O&M cost RAM, the simulations measure the financial impact of the RAM. When the ratio of the revenue requirements is less than 1.000, it means that the O&M RAM failed to achieve the allowed rate of return on rate base under the assumptions made in the simulations.

PEG also concludes that the growth in O&M costs is equal to the growth in input prices, less the increase in productivity, plus the growth in output. Output is often measure by the number of customers. Therefore, the resulting equation for the growth in O&M costs is:

$$\text{growth Cost}^{O\&M} = \text{growth Input Prices}^{O\&M} - \text{trend Productivity}^{O\&M} + \text{growth Customers.}$$

All significant forms of RAMs are subsets of this overall model for the growth in O&M expenses.

For example, the Revenue per Customer Freeze adjusts revenues by the growth in the number of customers. This RAM equates growth in revenue for growth in cost and further assumes that the growth in input prices is equal to the growth in productivity. As further discussed by PEG this assumption is generally unreasonable. Productivity is likely well below the growth in input prices, and the Revenue per Customer Freeze is likely to be uncompensatory for the utility.

Another example is the Inflation Only RAM that applies an inflation factor to O&M expenses. In this case, the RAM assumes that the growth in customers is equal to the growth in productivity. This may be reasonable in some cases, but applying a productivity factor without considering the growth in customers, or vice versa, does not have a reasonable economic premise and is likely to be unfair to either the utility or its customers.

In analyzing the results of its financial sufficiency simulations, PEG found that the Revenue Per Customer Freeze RAM approach was the most non-compensatory of the methods studied. Furthermore, the Revenue Per Customer Freeze approach was dependent on customer growth. The PEG Customer Input Price Index Hybrid approach (which uses escalators for O&M expenses and plant addition budgets based on a mix of forecasting and/or indexing as a basis for determining the return component of the RAM) is the closest to the SCE Hybrid RAM and

was more compensatory than the Inflation-Only approach. Based on these results and the terms of the HCEI Agreement regarding the revenue adjustment mechanism, the Companies further examined the hybrid approach. More details are available in PEGs report in Attachment 1.

Besides general indices such as consumer price index ("CPI-$U_{Honolulu}$") and U.S. gross domestic product price index ("GDPPI"), HECO sought to use industry-specific indices in the hybrid RAM. The Companies decided to use Global Insight indices because projected electric utility cost indices were available from Global Insight and the Global Insight series of indices are also used by SCE and approved by the California PUC. Attachment 3 includes the selected Global Insight indices used in the Companies' hybrid RAM simulations.

PEG's report provides the results of its study of alternative indices for use in the hybrid RAM. The plans noted "Hybrid I (PEG Customer Input Price Index)" through "Hybrid VII (HECO's 12 Category Decomposition)" applied escalators to O&M expenses only.

In analyzing the results, PEG stated that macroeconomic output price inflators like GDPPI and $CPI\text{-}U_{Honolulu}$ tend to underestimate O&M input price inflation. Also, both GDPPI and $CPI\text{-}U_{Honolulu}$ include components that are not relevant to O&M costs. Although GDPPI is a fairly stable inflator, $CPI\text{-}U_{Honolulu}$ places a heavier weight on price volatile elements such as food and energy. PEG found that these escalators provided the least compensation of the RAMs explored. However, the HECO Companies included them in the group of alternative RAMs because of their simplicity, despite their other drawbacks.

In addition to the study results presented by PEG, the HECO Companies used the following selection criteria to determine which of the O&M escalators to explore further. The hybrid RAM had to be:

1) Simple to implement with available data from HECO and/or other public sources;
2) Based on a justifiable economic premise;
3) Objective and fair to both shareholders and customers.

Based on the above criteria, it was noted that for the three-year rate case cycle results, the "Hybrid III (Full Indexation Using PEG Customer Index)" plan produced the highest financial coverage for all three HECO Companies in total. However, because this plan included customer growth as a driver for the RAM, it was not considered further.

The Hybrid I (PEG Custom Input Price Index) and Hybrid II (PEG 3 Category Decomposition) approaches required the identification of three employee classes (clerical, executive management, and professional). Since this identification would necessitate a significant amount of resources to develop the data for the HECO Companies, this approach also was not considered further. The Hybrid VI (Global Insight's Summary Electric Utility Materials and Services Price Index [JETOTALMS] RAM is simple, but the weights used for labor and nonlabor component of O&M costs do not represent the HECO Companies' share of the costs. Hybrid VII (HECO's 12-Category Decomposition) approach, discussed in more detail below, was thus chosen as the preferred RAM approach to escalate O&M expenses between rate cases.

This approach produced the least average revenue shortfall for the Companies in total, as shown in the following table.

Table 1. Historical Financial Sufficiency of Selected Hybrid RAMs

O&M RAM Alternative	Result*
1. GDPPI	0.973
2. CPI-$U_{Honolulu}$	0.973
3. Total O&M Materials and Services	0.990
4. Preferred: Labor/Non-labor Components	0.991

* Ratio of target vs. simulated revenue requirements. (See prior discussion of financial sufficiency simulations.)

The disadvantage of the preferred (Hybrid VII) approach is that it requires nine separate Global Insight indices to estimate twelve categories of O&M expenses for the

RAM. While the use of nine indices appears to be complex, the indices line up well with the same categories of expenses that are typically developed and presented in the HECO Companies' rate case filings. As a result, the derivation of the base O&M expense levels that would be escalated by the RAM is transparent and no additional studies or data development would be required to develop and justify the RAM-derived O&M expense estimates. Furthermore, Global Insight forecasts have long been approved by the California Public Utilities Commission for use in RAM development for many of the California energy utilities and are available to all parties.

Attachment 5A provides the preliminary calculation of the O&M expenses (without depreciation) for the 2010 and 2011 HECO RAM, based on HECO's proposed 2009 test year revenue requirement[5]. As noted in Attachment 5A, test year estimates of fuel and purchased power expenses (whose cost variation would be recovered through the ECAC and Purchased Power Adjustment clause), HCEI implementation studies (to be recovered through the REIP/CEI surcharge), demand-side management ("DSM") expenses, and SolarSaver costs are removed from O&M expense prior to applying the Global Insight indices to the labor and nonlabor expense categories to derive the post-test year target revenue requirement. Pension and OPEB expenses are also removed from the test year expense since recovery of these expenses are still subject to trackers approved on an interim basis in the HECO 2007, HELCO 2006, and MECO 2007 test year rate cases as reflected in the HCEI Agreement. The remaining expenses are then separated into labor and non-labor amounts based on HECO's 2009 budget then escalated, using the Global Insight's forecasted indices as follows:

[5] See Rate Case Update, HECO T-23, Attachment 2, page 1.

		Global Insight Cost Index	
	Expenses	for Salaries & Wages (Labor)[6]	for Other O&M NonLabor)[7]
1	Production	Electric Power, Generation, & T&D (CEU4422110008)	Steam Production (JEFOMMS)
2	Transmission	Electric Power, Generation, & T&D (CEU4422110008)	Transmission (JETOMMS)
3	Distribution	Electric Power, Generation, & T&D(CEU4422110008)	Distribution (JEDOMMS)
4	Customer Accounts	Utility Service Workers (CEU4422000008)	Customer Accounts (JECAOMS)
5	Customer Service	Utility Service Workers (CEU4422000008)	Customer Service (JECSIOMS)
6	Admin & General	Managers & Administrators (ECIPWMBFNS)	A&G (JEADGOMMS)

The fuel, purchased power, pension, and OPEB expenses that were removed earlier are then added back to the escalated amounts, then summed and "grossed up" for revenue taxes, as calculated for the 2009 test year, producing a new revenue requirement for 2010. The change between the newly-calculated 2010 revenue requirement and the test year revenue requirement is the estimated 2010 RAM. The calculation for the 2011 RAM is performed in the same manner as described, except using the 2010 calculated revenue requirement as its base.

Attachments 5B and 5C provide similar calculations for HELCO and MECO using the latest HELCO and MECO 2009 budget numbers.

The calculated O&M expense RAM adjustments to revenue requirements (in $ million), based on the impact of using the Global Insight cost indices for O&M expenses and the methodology as noted above, are as follows:

Company	2010	2011	2012	2013
HECO	$6.0M	$5.4M	N/A	N/A

[6] See Attachment 4-Global Insight, Power Planner, Third Quarter 2008, pages 48 and 60
[7] Ibid.

MECO	$1.6M	$1.4M	$1.6M	$1.7M
HELCO	$1.5M	$1.3M	$1.5M	$1.6M

Expressed as a percent of total base year revenue requirements[8], the O&M expense RAM impacts are show below:

Company	2010	2011	2012	2013
HECO	0.31%	0.28%	N/A	N/A
MECO	0.33%	0.29%	0.33%	0.35%
HELCO	0.29%	0.26%	0.29%	0.31%

In reviewing the preliminary calculations as reflected on Attachment 5A, the 2010 growth rate of labor expenses for HECO over the 2009 test year is estimated as 3.82%. This aligns reasonably well with HECO's union contract with Local 1260 of the International Brotherhood of Electrical Workers that reflects an across-the-board 4.25% increase in wages for all union workers[9] and HECO' budget assumption of 3% growth in merit salaries. The 2010 growth rate in non-labor expenses (without fuel and purchase power expenses) is calculated as 1.4% and total labor and non-labor expenses' growth rate is calculated as 2.26%, higher than the most recent 2010 GDPPI and CPI-U forecasts of 0.9% and 1.9%, respectively. MECO and HELCO both show very similar results for years 2010 and 2011. For years 2012 and 2013, both companies show labor expenses to grow at approximately 2.75% and 3.0%, respectively, and nonlabor expenses are forecasted to experience growth rates of approximately 1.6% and 1.8%. Thus, total O&M expenses without fuel and purchase power are forecasted to grow at approximately 2.1% for 2012 and 2013.

[8] HECO's 2009 test year revenue requirements = $1,967 million, MECO's 2009 estimated revenue requirements = $487 million, HELCO's 2009 estimated revenue requirements = $510 million.

[9] See Attachment 6-Amendment to Agreement between Hawaiian Electric Company, Inc. and Local 1260 of the International Brotherhood of Electrical Workers, Exhibit A, Classification and Wage Rates, effective November 1, 2007, pages 44-54.

Attachments 5A, 5B, and 5C are illustrative of the procedure that would be used to develop the RAM O&M expenses. For example, the actual 2010 RAM O&M expenses that will be calculated to adjust customers' rates (see section above on "Proposal for Decoupling and the Revenue Adjustment Mechanism ("RAM") Cycle") will be based on the 2009 test year revenue requirements as approved by the Commission in its Interim or Final Orders in the 2009 test year rate cases and the most recent Global Insight O&M expense forecasts available at that time. So the 2010 RAM O&M expenses would be estimated based on the forecasted indices in the Third Quarter 2009 issue of the Global Insight Power Planner that should be available in October 2009. The following post-test year RAM estimates of O&M expenses will follow the same procedure, i.e., the RAM O&M expenses will be estimated using the indices that are the most recently forecasted prior to the commencement of the RAM implementation year, applied to the approved test year expense amounts. So the actual RAM for O&M expenses that the Companies will received will not be known until a few months prior to the year that it will be implemented.

<u>RAM Calculation for Capital Costs</u>

The 2010 RAM adjustments to revenue requirements for the HECO Companies' capital costs are based on the differences between the calculation of 2010 operating income (return), which is the product of the projected 2010 average rate base and the authorized rate of return on rate base ("RORB") as approved by the Commission in the 2009 test year rate cases, and changes in depreciation expense and income taxes. As PEG notes in Attachment 1 at 20: "The index logic used to establish O&M budgets in hybrid RAMs is less useful --- and rarely used --- in establishing capex budgets". Capex budgets are routinely used in hybrid approaches to determine the average rate base that is used for the capital cost RAM adjustments.

In an effort to find an acceptable plant additions escalator for the calculation of the HECO Companies' average rate bases, similar to that used by Southern California Edison for its RAM, a regression analysis of recorded plant additions for the period 1999 through 2007 was performed (see WP 1). The results of this analysis showed that there was very little predictability in the total plant addition results for all HECO Companies as shown in the table below (which is not unexpected since the plant additions amount is significantly impacted by the timing of large plant additions). Therefore, the approach of basing the development of capital cost escalation on the trend in plant additions alone was put aside.

Regression Analysis for Historical Plant Addition Trends
1999 to 2007

Company	R-Square
HECO	0.53
HELCO	0.12
MECO	0.22

In order to develop the HECO Companies' proposal for the capital cost RAM, a larger and more stable series, average rate base, was selected in place of plant additions. Three different approaches were used to develop average rate base estimates. These approaches included:

1) Fully forecasted average rate bases, incorporating each utility's plant additions budget by project;
2) Estimated average rate bases calculated using results of regression analyses of the growth of the Companies' average rate bases during the period of 1996 through 2007; and

3) Estimated average rate bases calculated using results of regression analyses of the growth of the "normalized" average rate bases (i.e., without "significant projects"), then adding the rate base impact of the forecasted significant projects.

Further discussion of these approaches is provided below.

Forecasted Average Rate Base

The HECO Companies' forecasts of end of year and average rate bases are provided in Attachments 7A, B, and C which contain confidential information and are subject to the Protective Order approved and filed on January 6, 2009 in this proceeding. Also, depreciation expenses are estimated for the post-test year periods based on the forecasted growth rate of the average rate bases. To calculate the RAM adjustment for HECO, the proposed cost of capital, calculated income tax factors, and revenue tax factors developed for the 2009 test year were used. For MECO and HELCO, the RORB, income tax factor, and revenue tax factors approved by the Commission in the interim decision and orders issued in their last rate cases[10] are used to develop the RAMs for the capital costs during the post-test years. The estimated RAM impacts based on the Companies' forecasts are as follows:

Company	2010	2011	2012	2013
HECO	$26.2M	$15.5M	N/A	N/A
MECO	$1.5M	-$0.2M	-$0.7M	$0.4M
HELCO	$12.5M	$1.4M	-$1.5M	-$1.2M

[10] In the Interim Decision and Order No. 23926 issued on December 21, 2007 by the PUC in MECO's 2007 test year rate case, the Commission accepted a rate of return on rate base of 8.67% for the purpose of the interim award. In the Interim Decision and Order No. 23342 issued on April 4, 2007 by the PUC in HELCO's 2006 test year rate case, Docket No. 05-0315, the Commission accepted a return on rate base of 8.33% for the purpose of the interim award.

Expressed as a percent of total base year revenue requirements, the rate base RAM impacts are show below:

Company	2010	2011	2012	2013
HECO	1.33%	0.79%	N/A	N/A
MECO	0.31%	-0.04%	-0.14%	0.08%
HELCO	2.45%	0.28%	-0.29%	-0.24%

The calculations for the above estimates are provided as Attachments 8A, B, and C. Based on this methodology, the estimated RAM amounts are positive for all the Companies in 2010, then declining into the future. The decline is due primarily to the inability of the engineers to forecast individual projects out that far in time rather than a forecast or trend of what the rate bases level will be in the future.

Trended Average Rate Base

The regression analyses for the HECO Companies to estimate the annual increase in each company's respective average rate base are provided in Attachments 9A, B, and C. The results of the analysis are highly significant for all three companies (99% significance level). Based on these results, the analyses estimate that the average rate bases of HECO, MECO, and HELCO will increase by $30,637,815, $10,447,094, and $13,016,430, respectively. Based on these regression results and the same assumptions noted above for the RAM calculation based on the forecasted rate base, the RAM estimates for the post-test year are as follows:

Company	2010	2011	2012	2013
HECO	$6.3M	$6.3M	N/A	N/A
MECO	$2.3M	$2.3M	$2.3M	$2.3M
HELCO	$2.8M	$2.8M	$2.8M	$2.8M

Expressed as a percent of total base year revenue requirements, the rate base RAM impacts are show below:

Company	2010	2011	2012	2013
HECO	0.32%	0.32%	N/A	N/A
MECO	0.47%	0.47%	0.47%	0.47%
HELCO	0.55%	0.55%	0.55%	0.55%

The calculations for the above estimates are provided in Attachments 10A, B, and C. Because the rate bases grow by the same amount every year, the estimated RAM amounts are the same throughout the post-test years as well. This was a very simple and straightforward method to use in determining the RAM amount for rate base, but for Maui, produced RAM amounts much less than the RAM amounts based on the Companies' forecasts. Unless very large projects of the same magnitude of those anticipated to be placed into service are included in the historical data bases, the estimated average rate bases are significantly understated.

Adjusted Average Rate Base with Significant Projects

The HECO Companies also reviewed a "significant projects" approach.[11] First, the 1996 through 2007 actual average rate base amounts for each of the Companies were revised to remove the average rate base amounts associated with the significant projects that are noted on Attachments 11A, B, and C. For the first year that the individual significant project went into service, only half of the project's cost was removed. For the

[11] "Significant projects" are defined as capital projects that are larger than $20,000,000 for HECO, $10,000,000 for MECO and HELCO, and $20,000,000 for the HECO Companies on a consolidated basis. All thresholds are net of CIAC.

second year and beyond, because the actual rate base impact of the individual significant projects were not available, the average rate base impact for each project was calculated using the plant in service amount less an estimated depreciation reserve (based on the actual rate base factor for that year) and less an estimate of the accumulated deferred taxes (based on the actual rate base factor for that year).

Regression analyses of the revised average rate base data were then performed on the adjusted historical series (see Attachments 12A, B, and C). Based on the results of the regression analyses, the average rate bases for the HECO Companies were estimated. The rate base and depreciation impacts of the upcoming significant projects were then added to these amounts in the years that they are anticipated to be recorded. The following is a list of near-term projects that are handled as "significant projects" based on the thresholds noted:

1. HECO – CIP CT-1 (In service in 2009 Test Year);
2. HECO – East Oahu Transmission Project (Kamoku 46kV UG Alt Phase 1) ("EOTP Project") (In service in June 2010); and
3. HELCO – ST-7 (In Service in 2009 Test Year).

There are three different methods of adjusting the rate base RAM for upcoming significant projects. All three methods estimate rate bases that are based on the latest project cost estimates, but limit the addition to rate base to the project cost amount approved in the Company's capital improvement application pursuant to Rule 2.3.g.2 (or subsequently approved by the Commission), plus 10%. (The commitment of expenditures amount approved by the Commission has sometimes been larger than the amount included in the application due to revisions in the estimate during the course of the proceeding.) For those projects that are placed in service in the test year, the authorized amount + 10% would be used. The Companies would then have the opportunity to include the actual costs of the projects in its rate base in its next rate case. (Significant projects not yet identified that meet the $20 million/$10 million rate base threshold will also be included in the RAM.) As of this date, the only exception to this would be the EOTP project where pre-2003 planning and permitting costs would not be included in the calculation of the RAM (given the deferral of that issue to a ratemaking proceeding)[12]. The three methods also reflect the significant project's depreciation expense in the rate base RAM, beginning in the year after the project goes into service (see Attachments 13A, B, and C).

The first method includes the revenue requirement impact of the significant project's average rate base and depreciation expenses (in the year(s) following the scheduled plant-in-service date) in the RAM estimate. The RAM estimate is then reflected in customers' rates from January 1 and included in the RBA as an adjustment to target revenue requirements in that year (see RAM Adjustment in Rates, below). However, if the significant project is not placed into service during the year as anticipated, the cumulative monthly RAM amount associated with the significant project (with interest calculated from the beginning of the year) is reversed from the balancing account and credited to the next period's RAM.

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[12] In Docket No. 03-0417, HECO and the Consumer Advocate submitted a joint motion for approval of a stipulation on the proposed EOTP project stating that "(a)ny issue as to whether the pre-2003 planning and permitting costs, and the related AFUDC should be included in the costs of the instant project should be reserved to and may be raised in the next general rate increase proceeding (or other proceeding) in which HECO seeks approval to recover the East Oahu Transmission Project costs." (Joint Motion, page 5) The Commission granted approval of the provisions of the stipulation (Order No. 22104, page 4) and reaffirmed this in its decision and order on the project (D&O No. 23747, page 35). Therefore, these costs are not included in the costs of the project to be reserved for consideration in the next rate case and similarly, are not included here in the significant project costs for the RAM calculation.

The second method estimates the significant project's RAM impact as described above, using an average annual rate base and depreciation expenses in the year(s) following the scheduled plant in service date. However, the RAM impact on revenue requirements is not reflected in customers' rates that are in effect on January 1 of the year that the significant project is anticipated to be completed. If the significant project is placed into service during the year, the cumulative monthly RAM-related revenue requirement associated with it (with interest as if it were included in the RBA as a target revenue from the beginning of the year that the project goes into service) would be included in the RBA for collection in the following year. If the significant project is delayed or cancelled, the RAM revenue associated with it would not be reflected in the RBA as a target revenue adjustment in the following year.

The third method is the calculation of the impact of the significant projects, based on how the rate base impact of CIP CT-1 is calculated in the HECO 2009 test year rate case and the Steam Turbine generator ("ST-7") assumed to be authorized in 2009. [13] The full year's plant in service cost of the individual significant projects is reflected in the years they will be placed in service and for the remaining post-test years. For this calculation, the significant projects' costs will be limited to the Commission-approved amount plus 10%. (Significant project costs in the test year are assumed to be approved.) The exception is the EOTP project which will also exclude any pre-2003 preliminary planning costs. The associated depreciation expense for the individual significant projects is then reflected in the following year and post-test years for RAM development purposes (see Attachment 14). The following table reflects the anticipated average rate

[13] The ST-7 project costs are provided in monthly status reports in Docket No. 7623

base that will result if the HECO Companies' significant projects are completed on schedule.

Company	2010	2011	2012	2013
HECO-Trended Average RB	$1,350M	$1,365M	NA	NA
Add: Significant Projects	$86.2M	$90.8M	NA	NA
Adjusted Average RB	$1,436M	$1,456M	NA	NA
MECO-Trended Average RB	$407.0M	$411.6M	$416.2M	$420.8M
Add: Significant Projects	$0.0	$0.0	$0.0	$0.0
Adjusted Average RB	$407.0M	$411.6M	$416.2M	$420.8M
HELCO-Trended Average RB	$436.4M	$439.9M	$443.3M	$446.8M
Add: Significant Projects	$43.8M	$42.4M	$41.0M	$39.6M
Adjusted Average RB	$480.2M	$482.3M	$484.3M	$486.4M

Based on the table above, the calculated RAMs are as follows:

Company	2010	2011	2012	2013
HECO	$8.3M	$4.1M	N/A	N/A
MECO	$1.0M	$1.0M	$1.0M	$1.0M
HELCO	$12.8M	$0.5M	$0.5M	$0.5M

Expressed as a percent of total base year revenue requirements, the rate base RAM impacts are show below:

Company	2010	2011	2012	2013
HECO	0.42%	0.21%	N/A	N/A
MECO	0.21%	0.21%	0.21%	0.21%
HELCO	2.51%	0.10%	0.10%	0.10%

The amounts above are the estimated RAMs associated with the first two methods of dealing with significant projects where only half of the significant projects' capital costs are reflected in the year that they are placed in service (see Attachments 15A1. B, C).

For the third method where the full cost of a significant project would be reflected in the year it is placed into service, only HECO is affected since it is the only one of the Companies that has a significant project being placed into service post-test year, the EOTP project. The impact on the rate bases used to determine are shown below.

Company		2010	2011	2012	2013
HECO-Trended Average RB		$1,350M	$1,365M	N/A	N/A
	Add: Significant Projects-Full Cost	$94.6M	$90.8M	N/A	N/A
	Adjusted RB	$1,445M	$1,456M	N/A	N/A

Based on the adjusted rate base which reflects the full cost of the EOTP project for the full year in 2010, the estimated RAM amounts are as follows (see Attachment 15A2):

Company	2010	2011	2012	2013
HECO	$10.0M	$2.4M	N/A	N/A

Expressed as a percent of total base year revenue requirements, the rate base RAM impacts are show below:

Company	2010	2011	2012	2013
HECO	0.51%	0.12%	N/A	N/A

However, this higher RAM amount would be allocated into monthly amounts that would only be reflected in the RBA, beginning in the month that the significant projects are placed into service. Thus, in practice, each significant project would be required to have its own full cost RAM estimate for the year.

The significant projects methodology produces results that are between the Companies' forecasted rate bases and the estimated rate bases grown by the amount calculated by the regression analyses. Because of the large impact associated with the actual completion dates of the significant projects, the HECO Companies propose that the calculated RAM adjustments associated with these projects be reflected as a target revenue in the RBA upon the actual completion of the project, based on the third method described above. Thus, until a significant project is completed, there is no RAM included as a target revenue amount in the RBA and charged to customers. The RAM associated with the significant projects is reflected in Attachment 15.

Based on the above analyses, the HECO Companies propose that the development of the RAM be based on significant projects full cost approach.

THE DECOUPLING AND RAM PROCESS

Revenue Balancing Accounts

As discussed in the meeting between the Companies and the Consumer Advocate on December 16 and 17, 2008, the Companies will request the establishment of revenue balancing accounts ("RBAs") to record the monthly differences between the approved interim revenue requirement for electric sales revenues[14] in their 2009 test year rate cases and the electric sales revenues recorded (the comparison will be made with revenues for fuel and purchased power expenses removed). In its 2009 rate case (Docket No. 2008-0083), Rate Case Update, HECO T-1, pages 8-11, HECO proposed the establishment of an RBA to be implemented upon the issuance of an interim order by the Commission. A detailed description of the RBA, which was included in the Rate Case Update, is submitted as Attachment 1 to this proposal. The HECO Companies propose

[14] The allocation of the revenue requirements to the remaining months in the year will be specified in the Companies' tariffs. The allocation will be based on the mWh sales forecast during the period that the target revenue requirement remains in effect.

that separate target revenue requirements be established for residential customers and for a single collective group of commercial (including industrial) customers. Each of the HECO Companies would employ separate RBAs for residential customers and for commercial customers. For the purpose of calculating the monthly difference to record to the RBAs, recorded electric sales revenue includes revenue from regular and optional rate schedule charges plus revenue from any interim or final rate increase adjustments that are in effect.

As explained in Attachment 2, besides reflecting the accumulated monthly differences, the RBA will also reflect the accrual of interest at a rate equal to the then approved rate of return applied to the simple average of the beginning and ending monthly balances. Upon the issuance of the final decision and orders in the 2009 test year rate cases, the RBA would begin to accumulate the monthly differences between the recorded sales revenues and the final approved target revenues (the comparison will be made with revenues for fuel and purchased power expenses removed).

The estimated amounts in the year-end RBA balances will be cleared to customers in an RBA rate adjustment over the 12 months of the succeeding calendar year. In November of each year, the Companies will notify the Commission of the estimated RBA year-end balances (based on the estimated October 31 balances and the forecasted charges/credits to the RBAs, including interest for November and December of that year). The Companies will propose separate per kWh RBA rate adjustments, one for the residential customer RBA and one for the commercial customer RBA, that will apply to residential and commercial customers, respectively, over the next calendar year, that will collect/refund the expected RBA current year-end balance, based on the next calendar year's expected kWh sales. The revenue (or credits) from the RBA rate adjustments will be included in the recorded electric revenue that is compared to the revenue requirement targets for the calculation of the monthly differences to be added to (or subtracted from) the RBA balance.

Practically speaking, the above described timeline will only apply to HECO in 2009 since MECO and HELCO have not yet filed their 2009 test year general rate cases and the Companies anticipate that the interim decision and orders for these rate cases will not be issued until 2010. With the issuance of these interim decision and orders, MECO and HELCO should be allowed to apply the appropriate RAM indices to escalate the 2009 test year revenue requirements to reflect RAM adjustments for year 2010. The adjusted 2010 test year revenue requirements will then be used as the target revenue for 2010, and with the implementation of RBAs for MECO and HELCO, the same procedure as described above for HECO will apply.

RAM Adjustments in Rates

The HECO Companies will include in the RBA rate adjustments the calculated RAM adjustments for the same calendar year. In November of each year, the Companies will notify the Commission of the estimated RAM adjustment for the next calendar year. The Companies will separate the total RAM adjustment dollars into a residential RAM adjustment and a commercial RAM adjustment based on their respective shares of the total revenue requirement approved in the most recent final decision and order in a general rate case. The sum of the RBA balance and the total RAM adjustment dollars would be subject to the RBA threshold to determine if both the RBA and RAM adjustments are implemented. If the sum of the RBA balance and the total RAM adjustment dollars do not meet the threshold the amounts would be carried over into the following year's adjustments.

However, if the threshold is met, the respective residential and commercial RAM adjustments will be converted to cents per kWh using the same sales forecast that is employed to derive the RBA rate adjustment. The sum of the RBA rate adjustment plus the RAM adjustment equals the total per kWh adjustment that will be applied to residential and commercial customers, respectively, in the next calendar year. During a calendar year, if an interim or final decision and order in a general rate case generates a recalculation of the RAM adjustment for that calendar year, the HECO Companies may adjust the per kWh adjustment assigned to residential and commercial customers in that calendar year to reflect the necessary changes to the RAM adjustment.

HECO expects that the filing of the RBA balance and RBA rate adjustments including RAM adjustments to revenue requirements will take the form of a compliance filing requiring a minimum of regulatory review. The data components to the filing are the RBA balance and two months of projected and target revenues for November and December by customer class, the application of Commission-approved escalators to test year O&M expenses and rate base to derive the post-test year target revenue requirement (allocated to customer class), and projected residential and commercial sales for the following year. Therefore, since the data and computational complexity are limited, the need for a protracted review period is low.

MECO and HELCO have not yet filed their 2009 test year general rate cases and the Companies anticipate that the interim decision and orders for these rate cases will not be issued until 2010. With the issuance of these interim decision and orders, MECO and HELCO should be allowed to apply the appropriate RAM indices to escalate the 2009 test year revenue requirements approved in the interim decision to reflect RAM adjustments for year 2010, which will then be used as the target revenue for 2010.

RAM Adjustment Process

The HECO Companies' RAM adjustment process will be very similar to that used by Southern California Edison Company ("SCE"). In SCE's process, as described in its tariff sheets shown on Attachment 16, the key procedural steps are:

1. On November 1 of the post test year, SCE files an advice letter with the California PUC to implement updated post test year revenue requirements. (Attachment 17 is a sample of SCE's advice letter.)

2. The SCE advice letter includes the following information:
    a. The purpose of the advice letter.
    b. Background information on the GRC and the interim/final decision and order authorizing the automatic Post Test Year Ratemaking ("PTYR") mechanism (equivalent to the HECO Companies' proposed RAM).
    c. Implementation of the new GRC-authorized revenue requirements by showing calculations of the authorized return for each component, and the total.
    d. Tariff sheets affected.
    e. Effective date of the rate changes.
    f. Notice to any party who wishes to file a protest.

3. The effective date of the rate change is January 1 of the following calendar year (Attachment 17 at 5).

4. Anyone wishing to protest the advice filing may do so by letter via US Mail, facsimile, or electronically, no later than 20 days after the date of the advice filing (Attachment 17 at 5).

Similar to the Integrated Resource Planning ("IRP") Cost Recovery Provision, the revenue decoupling mechanism (i.e. the RBA and RAM) is an automatic rate adjustment clause. Therefore, the HECO Companies will file the RBA and RAM tariff changes through transmittal letter, as it does to file tariff changes for other automatic rate adjustment clauses. Furthermore, the HECO Companies propose to follow a process with procedural steps similar to the SCE process. On a preliminary basis, the HECO Companies' process is as follows:

1. On the last business day of November of the post test year, HECO Companies will file a tariff with the Commission to implement updated post test year revenue requirements.

2. The transmittal letter for the proposed tariff will include contents similar to SCE's advice letter as described above.

3. The effective date of the rate change will be January 1 of the following calendar year.

4. Anyone wishing to protest the tariff filing may do so pursuant to Hawaii Administrative Rules ("HAR") § 6-61-58 and 61.

<u>Notification of Target Revenue Requirement and RBA Rate Adjustments</u>

The HECO Companies will file tariff sheets that show the monthly target revenue requirements for the calendar year and the applicable RBA rate adjustment in cents per kWh. Separate target revenue requirements and RBA rate adjustments will be presented for residential and commercial customers. In the filing, workpapers will be provided that support the derivation and calculation of the monthly revenue requirements and the per kWh charges.

The initial tariff sheet filing is expected for HECO at the time of the interim decision and order in the test year 2009 rate case. At that point the tariff filing will include only the monthly target revenue requirement for the purposes of calculating amounts to be attributed to the RBA accounts.

In November 2009, HECO would make a proposed tariff filing to be effective January 1, 2010 to December 31, 2010. The monthly target revenue requirements for

2010 would be based on the revenue requirements for test year 2009 approved in the interim decision and order (assuming that a final order in the case is still pending) plus the RAM adjustments for 2010. The RBA rate adjustments for 2010 would be based on the expected balance in the RBA accounts at year end 2009 plus the RAM adjustments for 2010. Supporting workpapers for the calculation of the estimated 2009 year end RBA balances, the 2010 RAM adjustments, and the calculation of the RBA rate adjustments would be included in the filing.

HECO expects to make subsequent tariff filings in November of each year to establish the target revenue requirements for the next calendar year based on the RAM adjustment and to re-set the RBA rate adjustments for the next calendar year based on clearing out the expected RBA balances at the end of the current calendar year plus recovering the RAM adjustment for the next calendar year.

In addition, HECO will make tariff filings when necessary during the year to re-set target revenue requirements and to re-set RBA rate adjustments for re-calculated RAM adjustments based on issuance of interim or final decision and orders in pending rate cases.

HELCO and MECO will follow the same notice procedures described above, commencing with an interim decision and order in their test year 2009 rate cases. However, since such interim decision and orders are not expected until 2010, the initial target revenue requirements for 2010 filed for HELCO and MECO should be based on the test year 2009 revenue requirement approved in the interim decision and order plus the appropriate RAM adjustment for 2010.

ON-GOING REVIEW OF REVENUE DECOUPLING

Sales decoupling and revenue adjustment mechanisms have been used in many jurisdictions without major difficulties (see PEG's report). The HECO Companies maintain that they have used the lessons learned from some of these jurisdictions to reduce the possibility of problems in implementation. However, there may still be concerns by the Commission and Consumer Advocate regarding the risk of unintended consequences resulting from the move to a new ratemaking regime in Hawaii. To reduce this risk, the Companies are proposing to implement a number of "exit ramps", which provide the Commission, the Consumer Advocate, and the Companies the ability to review the performance of revenue decoupling and take steps to correct, suspend, or terminate the mechanism.

A number of review provisions are included in the HCEI Agreement. They include the following:

> 2. The parties agree that the decoupling mechanism that will be implemented will be subject to review and approval by the PUC.
>
> 4. The Commission may review the decoupling mechanism at any time if it determines that the mechanism is not operating in the interests of the ratepayers.
>
> 5. The utility or the Consumer Advocate may also file a request to review the impact of the decoupling mechanism.
>
> 6. The Commission may unilaterally discontinue the decoupling mechanism if it finds that the public interest requires such action.

The HECO Companies propose to adopt all of the above HCEI Agreement review provisions. The Companies propose that this decoupling docket remain open for two year following the Commission's final decision and order. Utility or Consumer Advocate requests to review the impact of the decoupling mechanism could then be filed under this docket. The request to review should include the basis for the request, supporting workpapers and exhibits identifying the facts underlying the basis for the request, and a proposed timeline for Commission review of the request. The Commission's review would reasonably require a response by either the Consumer Advocate or HECO Companies.

The HECO Companies also acknowledge under their proposal the Commission may unilaterally discontinue the decoupling mechanism if it finds that the public interest requires such action. However, the HECO Companies request that Commission recognize that the public interest consists of both a short-term and long-term interest. Therefore, while during the short-term electricity rates may rise should electricity sales lag behind test year sales, the long-term benefits have great value to utility customers and the Hawaii community as a whole.

The decoupling mechanism leads to full utility support of energy efficiency and on-site renewable generation that provides options for its customers to manage their electricity bill. These measures also reduce the state's dependence on oil imports from foreign destinations and, hence, increase energy sustainability and security. The decoupling mechanism also supports a financially sound electric utility that is financially capable of making the investments necessary to increase the amount of renewable energy on the system, attain the renewable portfolio standards, and further enhance the state's energy security.

These long-term benefits are significant and are supported by community stakeholders, major leaders in government, and by the HECO Companies. Therefore, these benefits should not be ignored or discounted when reviewing the impact of the decoupling mechanism and the public interest.

The HECO Companies have not proposed an earnings sharing mechanism, but would be willing to consider one if it operated symmetrically both above and below a baseline and was fair to both customers and shareholders of the Companies.

SUMMARY

Revenue decoupling supports energy efficiency and customer-sited renewable generation, initiatives that have broad community support due their positive impacts on oil independence, energy self-sufficiency, and energy security. Revenue decoupling also provides the electric utilities with the financial ability to preserve a stable electric grid to minimize disruption to service quality and reliability and retain the capacity to invest in infrastructure necessary to achieve an independent renewable energy future.

Major stakeholders, including the Governor of the State of Hawaii, the Division of Consumer Advocacy of the State of Hawaii Department of Commerce and Consumer Affairs, and the HECO Companies signed the landmark HCEI Agreement in October 2008 committing to support revenue decoupling because of its significant potential contribution to the public benefit and to support the need for a financially sound electric utility that is necessary to achieve the system reliability objectives and independent renewable future.

The HECO Companies have proposed revenue decoupling with two components: sales decoupling and a RAM. The sales decoupling mechanism breaks the link between sales and revenue, while the RAM provides the utilities the opportunity to recover its costs between rate cases to maintain their financial health. This hybrid approach to the

RAM is similar to what is currently in place for major California electric utilities and is consistent with the provisions of the HCEI Agreement.

The HECO Companies maintain that their proposal to establish a RBA and implement their preferred hybrid RAM meets the above objectives, complies with the provisions of the HCEI Agreement, and are objective and fair to both shareholders and customers.

The HCEI Agreement addresses decoupling from sales for all HECO Companies (see pages 32 and 33). The HCEI Agreement identifies two mechanisms that together combine to implement decoupling from sales:

1. Revenue decoupling: "The revenues of the utility will be fully decoupled from sales/revenues beginning with the interim decision in the 2009 Hawaiian Electric Company Rate Case (most likely in the summer of 2009)."[1]
2. Revenue adjustment mechanism (a mechanism to adjust utility rates for trends in input prices, demand, and other external business conditions that affect utility earnings): "The utility will use a revenue adjustment mechanism based on cost tracking indices such as those used by the California regulators for their larger utilities or its equivalent and not based on customer count. Such a decoupling mechanism would, on an ongoing basis, provide revenue adjustments for the differences between the amount determined in the last rate case and:
   - (a) The current cost of operating the utility that is deemed reasonable and approved by the PUC;
   - (b) Return on and return of ongoing capital investment (excluding those projects included in the Clean Energy Infrastructure Surcharge); and
   - (c) Any changes in State or federal tax rates."[2]

[1] HCEI Agreement, page 33.
[2] HCEI Agreement, page 33.

On October 24, 2008, the Commission issued an Order Initiating Investigation and opened Docket No. 2008-0274 ("Decoupling Docket") to examine implementing a decoupling mechanism for the HECO Companies. The Order required that the HECO Companies and the Consumer Advocate submit to the Commission a joint proposal on decoupling that addresses all of the factors identified in the HCEI agreement within 60 days.[3]

In meetings between the Consumer Advocate and HECO, it was agreed that HECO would initiate the revenue decoupling mechanism upon receipt of an interim order in the HECO 2009 rate case by proposing to establish a revenue balancing account ("RBA") in its HECO 2009 rate case update.

The RBA proposed by HECO would remove the linkage between electric revenues and sales immediately upon the approval of an interim rate increase in the HECO 2009 rate case as follows:

1. The target base revenue for the remainder of 2009 (assuming that interim approval is received in 2009) would be the revenue requirement approved by the Commission in the interim decision adjusted for the revenue requirements for fuel and purchased power. This revenue would be allocated by month and prorated within the month of the issuance of the interim order.
2. The RBA would accumulate the monthly difference between actual recorded electric revenues and the target revenues, both adjusted for revenue requirements for fuel and

[3] Subsequently, in its December 3, 2008 Order in this docket, the Commission extended the deadline for the joint proposal to February 17, 2009.

purchased power for the period between the date of interim rate relief and the effective date of final rates.

3. The proposed RBA will also reflect the accrual of interest at the rate of the then-approved rate of return applied to the simple average of the beginning and ending balance in the balancing account each month.
4. On the effective date of the final rates (approved in the final decision and order for this rate case) the RBA would begin to accumulate the monthly difference between actual recorded electric sales revenues and the final approved target revenue, both adjusted for the revenue requirements of fuel and purchased power.
5. It is anticipated that HECO will also establish a process with Commission approval that would allow the recovery/refund of any under/over collection of electric sales revenues as reflected in the RBA. An example of such a process is as follows:
   a. On November 30, 2009, HECO would notify the Commission and the Consumer Advocate of: 1) the estimated year-end balance in the RBA based on the October 31, 2009 balance and the forecasted charges/credits to the RBA, including interest, for November and December 2009; and 2) the tariff rates that reflect the inclusion of the estimated recovery/refund of the estimated year-end RBA balance
   b. Based on the assumption that the Commission would have approved a revenue adjustment mechanism ("RAM"), the new rates would also reflect the new revenue requirement developed by the RAM, to be effective on January 1, 2010.

It is HECO's intention that a RAM will be further discussed in a proposal submitted in the Decoupling Docket. HECO also intends that the proposal will include provisions agreed upon between the Consumer Advocate and HECO that will outline the scope and timing for additional work on the RAM. In the Decoupling Docket, the proposal for the RAM will be submitted and reviewed per the procedural schedule to be approved by the Commission.

Confidential Information Deleted Pursuant To Protective Order, Filed on January 6, 2009.

DOCKET NO. 2008-0274
ATTACHMENTS 2-3

Attachments 2 and 3 contain confidential information and are provided subject to the Protective Order filed on January 6, 2009 in this proceeding.

POWER PLANNER

THIRD QUARTER 2008

GLOBAL INSIGHT

TABLE A21

Summary Operations and Maintenance Costs: Combined Materials and Services

(TREND 083)

(1992=1.000)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
ELECTRIC EXPENSES	[redacted]											
Total Operation and Maintenance: JETOTALMS												
%												
Steam Production Plant: JEFOMMS												
%												
Nuclear Production Plant: JENOMMS												
%												
Hydro Production Plant: JEHOMMS												
%												
Other Production Plant: JEOOMMS												
%												
Transmission Plant: JETOMMS												
%												
Distribution Plant: JEDOMMS												
%												
Customer Accounts: JECAOMS												
%												
Customer Service and Information: JECSIOMS												
%												
Sales: JESALOMS												
%												
Administrative and General: JEADGOMMS												
%												
GAS EXPENSES												
Total Operation and Maintenance: JGTOTALMS												
%												
Underground Storage: JGUSOMMS												
%												
Other Storage: JGOSOMMS*												
%												
LNG Terminaling and Processing: JGLNGOMMS*												
%												
Transmission: JGTOMMS												
%												
Distribution: JGDOMMS*												
%												
Customer Accounts: JGCAOMS												
%												
Customer Service and Information: JGCSIOMS												
%												
Sales: JGSALOMS												
%												
Administrative and General: JGADGOMMS												
%												

* These major expense category indexes are formed using equal weight assumptions

Confidential Information Deleted Pursuant To Protective Order, Filed on January 6, 2009.

TABLE A30

Utility Price and Wage Indicators

(TREND 083)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
WAGES	[redacted]											
Utility Service Workers: CEU4422000008												
%												
Electric Power Generation, Transmission & Distr. Work CEU4422110008												
%												
Managers and Administrators: ECIPWMBFNS												
%												
Professional and Technical Workers: ECIPWPARNS												
%												
PRICES												
Gasoline: PPI3241101												
%												
Light Fuel Oils: PPI3241104												
%												
Heavy Fuel Oils, including No. 5, No.6, heavy diesel, gas enrichment oils: PPI3241105												
%												
Railroads; Line Haul Operations: PPI482111												
%												

JGT859	GAS TRANS., OTHER EXPENSES COST INDEX (LMS)
JGT859MS	GAS TRANS., OTHER EXPENSES COST INDEX (MS)
JGT862	GAS TRANS., MAINTENANCE OF STRUCTURES COST INDEX (LMS)
JGT862MS	GAS TRANS., MAINTENANCE OF STRUCTURES COST INDEX (MS)
JGT863	GAS TRANS., MAINTENANCE OF MAINS COST INDEX (LMS)
JGT863MS	GAS TRANS., MAINTENANCE OF MAINS COST INDEX (MS)
JGT864	GAS TRANS., MAINTENANCE OF COMPRESSOR STATION EQUIP. COST INDEX (LMS)
JGT864MS	GAS TRANS., MAINTENANCE OF COMPRESSOR STATION EQUIP. COST INDEX (MS)
JGT865	GAS TRANS., MAINT. OF MEASURING & REGULATING STATION EQUIP. COST INDEX (LMS)
JGT865MS	GAS TRANS., MAINT. OF MEASURING & REGULATING STATION EQUIP. COST INDEX (MS)
JGT866	GAS TRANS., MAINTENANCE OF COMMUNICATION EQUIP. COST INDEX (LMS)
JGT866MS	GAS TRANS., MAINTENANCE OF COMMUNICATION EQUIP. COST INDEX (MS)
JGT867	GAS TRANS., MAINTENANCE OF OTHER EQUIP. COST INDEX (LMS)
JGT867MS	GAS TRANS., MAINTENANCE OF OTHER EQUIP. COST INDEX (MS)
JGUSM	UNDERGR. STORAGE MAINTENANCE COST INDEX (LMS)
JGUSMMS	UNDERGR. STORAGE MAINTENANCE COST INDEX (MS)
JGUSO	UNDERGR. STORAGE OPERATION COST INDEX (LMS)
JGUSOM	TOTAL UNDERGR. STORAGE OPERATION AND MAINTENANCE COST INDEX (LMS)
JGUSOMMS	TOTAL UNDERGR. STORAGE OPERATION AND MAINTENANCE COST INDEX (MS)
JGUSOMS	UNDERGR. STORAGE OPERATION COST INDEX (MS)
JGUS815	UNDERGR. STORAGE, MAPS AND RECORDS EXPENSES COST INDEX (LMS)
JGUS815MS	UNDERGR. STORAGE, MAPS AND RECORDS EXPENSES COST INDEX (MS)
JGUS816	UNDERGR. STORAGE, WELLS EXPENSES COST INDEX (LMS)
JGUS816MS	UNDERGR. STORAGE, WELLS EXPENSES COST INDEX (MS)
JGUS817	UNDERGR. STORAGE, LINES EXPENSES COST INDEX (LMS)
JGUS817MS	UNDERGR. STORAGE, LINES EXPENSES COST INDEX (MS)
JGUS818	UNDERGR. STORAGE, COMPRESSOR STATION EXPENSES COST INDEX (LMS)
JGUS818MS	UNDERGR. STORAGE, COMPRESSOR STATION EXPENSES COST INDEX (MS)
JGUS819MS	UNDERGR. STORAGE, COMPRESSOR STATION FUEL & POWER EXPENSES COST INDEX (MS)
JGUS820	UNDERGR. STORAGE, MEASURING & REGULATING STATION EXPENSES COST INDEX (LMS)
JGUS820MS	UNDERGR. STORAGE, MEASURING AND REGULATING STATION EXPENSES COST INDEX (MS)
JGUS821	UNDERGR. STORAGE, PURIFICATION EXPENSES COST INDEX (LMS)
JGUS821MS	UNDERGR. STORAGE, PURIFICATION EXPENSES COST INDEX (MS)
JGUS822	UNDERGR. STORAGE, PURIFICATION EXPENSES COST INDEX (LMS)
JGUS822MS	UNDERGR. STORAGE, PURIFICATION EXPENSES COST INDEX (MS)
JGUS824	UNDERGR. STORAGE, OTHER EXPENSES COST INDEX (LMS)
JGUS824MS	UNDERGR. STORAGE, OTHER EXPENSES COST INDEX (MS)
JGUS831	UNDERGR. STORAGE, MAINTENANCE OF STRUCTURES COST INDEX (LMS)
JGUS831MS	UNDERGR. STORAGE, MAINTENANCE OF STRUCTURES COST INDEX (MS)
JGUS832	UNDERGR. STORAGE, MAINTENANCE OF RESERVOIRS AND WELLS OST INDEX (LMS)
JGUS832MS	UNDERGR. STORAGE, MAINTENANCE OF AND WELLS COST INDEX (MS)
JGUS833	UNDERGR. STORAGE, MAINTENANCE OF LINES COST INDEX (LMS)
JGUS833MS	UNDERGR. STORAGE, MAINTENANCE OF LINES COST INDEX (MS)
JGUS834	UNDERGR. STORAGE, MAINTENANCE OF COMPRESSOR STATION EQUIP. COST INDEX (LMS)
JGUS834MS	UNDERGR. STORAGE, MAINTENANCE OF COMPRESSOR STATION EQUIP. COST INDEX (MS)
JGUS835	UNDERGR. STOR., MAINT. OF MEASURING & REGULATING STAT. EQUIP. COST INDEX (LMS)
JGUS835MS	UNDERGR. STOR., MAINT. OF MEASURING & REGULATING STATION EQUIP. COST INDEX (MS)
JGUS836	UNDERGR. STORAGE, MAINTENANCE OF PURIFICATION EQUIP. COST INDEX (LMS)
JGUS836MS	UNDERGR. STORAGE, MAINTENANCE OF PURIFICATION EQUIP. COST INDEX (MS)
JGUS837	UNDERGR. STORAGE, MAINTENANCE OF OTHER EQUIP. COST INDEX (LMS)
JGUS837MS	UNDERGR. STORAGE, MAINTENANCE OF EQUIP. COST INDEX (MS)
JRENT	RENT EXPENSES COST INDEX
JRENT931	ACCOUNT 931 RENTAL EXPENSES COST INDEX
JS&EMS	SUPERVISION AND ENGINEERING EXPENSES COST INDEX (MS)

Attachments 5A, 5B, and 5C contain confidential information and are provided subject to the Protective Order filed on January 6, 2009 in this proceeding.

AMENDMENT TO AGREEMENT

between

HAWAIIAN ELECTRIC COMPANY, INC.

and

LOCAL 1260
OF THE
INTERNATIONAL BROTHERHOOD
OF ELECTRICAL WORKERS
AFL-CIO

EXHIBIT A
CLASSIFICATION AND WAGE RATES

Effective Date: November 1, 2007
Terminates: October 31, 2010

HAWAIIAN ELECTRIC COMPANY, INC.
EXHIBIT A
(continued)

				+7.5%	+12.0%	
			+3.5%	+4.0%	+4.5%	Non-compounded annual increase. 11/1/06 as base rate
JOB CODE	**JOB TITLE**	11/1/06	**11/1/2007**	**1/1/2009**	**1/1/2010**	
CL737	MAIL CLERK					
	1st 6 mos.	9.73	10.07	10.46	10.90	
	Next 6 mos.		10.60	11.01	11.47	
	Next 6 mos.		11.10	11.52	12.01	
	Thereafter		11.65	12.10	12.61	
CL01	CLERK TYPIST I					
	1st 6 mos.		11.10	11.52	12.01	
	Next 6 mos.		11.65	12.10	12.61	
	Next 6 mos.		12.20	12.67	13.20	
	Thereafter		12.79	13.29	13.84	
TL14	CONSTRUCTION HELPER					
	1st 6 mos.		12.50	12.99	13.53	
	Thereafter		13.13	13.64	14.21	
TL204	SERVICE STATION ATTENDANT					
TL704	MAIL DRIVER					
	1st 6 mos.		11.65	12.10	12.61	
	Next 6 mos.		12.20	12.67	13.20	
	Next 6 mos.		12.79	13.29	13.84	
	Thereafter		13.43	13.95	14.54	
CL635	PRINTER I					
	1st 6 mos.		12.79	13.29	13.84	
	Next 6 mos.		13.43	13.95	14.54	
	Thereafter		14.10	14.64	15.25	
TL258	AUTO POOL ATTENDANT I					
	1st 6 mos.		12.79	13.29	13.84	
	Next 6 mos.		13.43	13.95	14.54	
	Next 6 mos.		14.10	14.64	15.25	
	Thereafter		14.80	15.37	16.02	
CL02	CLERK TYPIST II					
	1st 6 mos.		13.43	13.95	14.54	
	Next 6 mos.		14.10	14.64	15.25	
	Next 6 mos.		14.80	15.37	16.02	
	Next 6 mos.		15.49	16.09	16.77	
	Thereafter		16.30	16.93	17.64	
TL08	HELPER 1/C					
TL17	MAINTENANCE HELPER					
	1st 3 mos.		13.13	13.64	14.21	
	Next 3 mos.		13.78	14.31	14.91	
	Next 6 mos.		14.45	15.01	15.64	
	Next 6 mos.		15.16	15.75	16.41	
	Next 6 mos.		15.91	16.52	17.21	
	Thereafter		16.68	17.33	18.05	

HAWAIIAN ELECTRIC COMPANY, INC.
EXHIBIT A
(continued)

JOB CODE	JOB TITLE	11/1/2007	1/1/2009	1/1/2010
CL05	ACCOUNT SERVICES CLERK I			
CL713	TELEPHONE OPER/RECEPTIONIST			
	1st 6 mos.	13.43	13.95	14.54
	Next 6 mos.	14.10	14.64	15.25
	Next 6 mos.	14.80	15.37	16.02
	Next 6 mos.	15.49	16.09	16.77
	Next 6 mos.	16.30	16.93	17.64
	Thereafter	17.11	17.77	18.51
TL15	CUSTODIAN I			
	1st 3 mos	12.79	13.29	13.84
	Next 3 mos	13.43	13.95	14.54
	Next 3 mos	14.10	14.64	15.25
	Next 3 mos	14.80	15.37	16.02
	Next 3 mos.	15.49	16.09	16.77
	Next 6 mos.	16.30	16.93	17.64
	Thereafter	17.11	17.77	18.51
CL667	PRINTER II			
CL748	MAIL MACHINE OPERATOR			
CL750	SENIOR MAIL CLERK			
	1st 3 mos.	14.45	15.01	15.64
	Next 3 mos.	15.16	15.75	16.41
	Next 3 mos.	15.91	16.52	17.21
	Next 6 mos.	16.68	17.33	18.05
	Next 6 mos.	17.50	18.18	18.94
	Thereafter	18.37	19.08	19.88
CL04	ACCOUNTING CLERK II			
CL19	CLAIMS CLERK			
	1st 6 mos.	15.16	15.75	16.41
	Next 6 mos.	15.91	16.52	17.21
	Next 6 mos.	16.68	17.33	18.05
	Next 6 mos.	17.50	18.18	18.94
	Thereafter	18.37	19.08	19.88
CLC16	WORD PROCESSING OPERATOR			
	1st 3 mos.	14.80	15.37	16.02
	Next 3 mos.	15.49	16.09	16.77
	Next 3 mos.	16.30	16.93	17.64
	Next 6 mos.	17.11	17.77	18.51
	Next 6 mos.	17.95	18.64	19.42
	Thereafter	18.82	19.54	20.36
CLC01	INFO STORAGE EQUIP OPER			
	1st 3 mos.	15.91	16.52	17.21
	Next 3 mos.	17.50	18.18	18.94
	Next 6 mos.	18.37	19.08	19.88
	Thereafter	19.31	20.06	20.90

HAWAIIAN ELECTRIC COMPANY, INC.
EXHIBIT A
(continued)

JOB CODE	JOB TITLE	11/1/2007	1/1/2009	1/1/2010
TL260	TIRE REPAIRER			
	1st 6 mos.	15.91	16.52	17.21
	Next 6 mos.	17.50	18.18	18.94
	Next 6 mos.	18.37	19.08	19.88
	Thereafter	19.31	20.06	20.90
CL03	CLERK TYPIST III			
	1st 6 mos.	15.49	16.09	16.77
	Next 6 mos.	16.30	16.93	17.64
	Next 6 mos.	17.11	17.77	18.51
	Next 6 mos.	17.95	18.64	19.42
	Next 6 mos.	18.82	19.54	20.36
	Thereafter	19.74	20.50	21.36
T105	(S) OPERATOR TRAINEE	20.20	20.98	21.86
TL09	SENIOR HELPER			
	1st 3 mos.	15.91	16.52	17.21
	Next 3 mos.	16.68	17.33	18.05
	Next 6 mos.	17.50	18.18	18.94
	Next 6 mos.	18.37	19.08	19.88
	Next 6 mos.	19.31	20.06	20.90
	Thereafter	20.24	21.03	21.91
TL16	CUSTODIAN II			
	1st 3 mos.	17.95	18.64	19.42
	Next 3 mos.	18.82	19.54	20.36
	Next 6 mos.	19.74	20.50	21.36
	Thereafter	20.73	21.53	22.43
CL09	ACCOUNTING CLERK III			
CL720	PURCHASING CLERK I			
CL1007	ACCOUNT SERVICES CLERK II			
	1st 3 mos.	16.68	17.33	18.05
	Next 3 mos.	17.50	18.18	18.94
	Next 3 mos.	18.37	19.08	19.88
	Next 6 mos.	19.31	20.06	20.90
	Next 6 mos.	20.24	21.03	21.91
	Thereafter	21.24	22.06	22.98
CL11	DRAWING CONTROL CLERK			
	1st 6 mos.	16.68	17.33	18.05
	Next 6 mos.	17.50	18.18	18.94
	Next 6 mos.	18.37	19.08	19.88
	Next 6 mos.	19.31	20.06	20.90
	Next 6 mos.	20.24	21.03	21.91
	Thereafter	21.24	22.06	22.98
TL296	MECHANIC HELPER			
	1st 3 mos.	16.30	16.93	17.64
	Next 3 mos.	17.11	17.77	18.51
	Next 6 mos.	18.82	19.54	20.36
	Next 6 mos.	19.74	20.50	21.36
	Next 6 mos.	20.73	21.53	22.43
	Thereafter	21.77	22.61	23.55

HAWAIIAN ELECTRIC COMPANY, INC.
EXHIBIT A
(continued)

JOB CODE	JOB TITLE	11/1/2007	1/1/2009	1/1/2010
CLG05	METER READING CLERK			
	1st 3 mos.	17.11	17.77	18.51
	Next 3 mos.	17.95	18.64	19.42
	Next 3 mos.	18.82	19.54	20.36
	Next 6 mos.	19.74	20.50	21.36
	Next 6 mos.	20.73	21.53	22.43
	Thereafter	21.77	22.61	23.55
TL285	FACILITY OPERATIONS MECHANIC			
	1st 3 mos.	17.95	18.64	19.42
	Next 3 mos.	18.82	19.54	20.36
	Next 6 mos.	19.74	20.50	21.36
	Next 6 mos.	20.73	21.53	22.43
	Thereafter	21.77	22.61	23.55
CL829	CASHIER			
	1st 3 mos.	17.56	18.24	19.01
	Next 3 mos.	18.37	19.08	19.88
	Next 3 mos.	19.31	20.06	20.90
	Next 6 mos.	20.24	21.03	21.91
	Next 6 mos.	21.24	22.06	22.98
	Thereafter	22.28	23.14	24.11
CLC05	SR INFO STORAGE EQUIP OPER			
CL18	SYSTEM OPERATION CLERK			
CL104	POWER PLANT CLERK			
CL257	MOTOR FLEET CLERK			
CL328	METER CLERK			
CL604	PRINTER III			
CL684	COMPUTER SYSTEMS OPER TRAINEE			
	1st 3 mos.	17.95	18.64	19.42
	Next 3 mos.	18.82	19.54	20.36
	Next 3 mos.	19.74	20.50	21.36
	Next 6 mos.	20.73	21.53	22.43
	Next 6 mos.	21.77	22.61	23.55
	Thereafter	22.81	23.69	24.68
TL180	CONDENSER CLEANER			
	1st 6 mos.	19.74	20.50	21.36
	Next 6 mos.	20.73	21.53	22.43
	Next 6 mos.	21.77	22.61	23.55
	Thereafter	22.81	23.69	24.68
CLA49	PROJECT CLERK			
CLA81	STANDARDS CLERK			
CL12	JOINT POLE AIDE			
CL13	PROJECT CLERK			
CL15	FIELD SERVICE CLERK			
	1st 3 mos.	18.37	19.08	19.88
	Next 3 mos.	19.31	20.06	20.90
	Next 3 mos.	20.24	21.03	21.91
	Next 6 mos.	21.24	22.06	22.98
	Next 6 mos.	22.28	23.14	24.11
	Thereafter	23.41	24.32	25.33

HAWAIIAN ELECTRIC COMPANY, INC.
EXHIBIT A
(continued)

JOB CODE	JOB TITLE	11/1/2007	1/1/2009	1/1/2010
T335	TRUCK DRIVER A	23.44	24.35	25.37
CL406	METER READER			
	1st 3 mos.	17.95	18.64	19.42
	Next 3 mos.	18.82	19.54	20.36
	Next 6 mos.	20.73	21.53	22.43
	Next 6 mos.	21.77	22.61	23.55
	Next 6 mos.	22.81	23.69	24.68
	Thereafter	23.96	24.89	25.93
CL1013	INVOICE PAYMENT CLERK			
CLD31	SR WORD PROCESSING OPERATOR			
CL17	FUELS RECORDS CLERK			
	1st 3 mos.	19.31	20.06	20.90
	Next 3 mos.	20.24	21.03	21.91
	Next 3 mos.	21.24	22.06	22.98
	Next 6 mos.	22.28	23.14	24.11
	Next 6 mos.	23.41	24.32	25.33
	Thereafter	24.56	25.51	26.58
CL1011	PURCHASING CLERK			
	1st 3 mos.	20.24	21.03	21.91
	Next 3 mos.	21.24	22.06	22.98
	Next 6 mos.	22.28	23.14	24.11
	Next 6 mos.	23.41	24.32	25.33
	Thereafter	24.56	25.51	26.58
CL06	CONSTRUCTION & MAINTENANCE DIVISION CLERK			
	1st 3 mos.	21.24	22.06	22.98
	Next 6 mos.	22.28	23.14	24.11
	Next 6 mos.	23.41	24.32	25.33
	Thereafter	24.56	25.51	26.58
T336	TRUCK DRIVER B	25.20	26.18	27.27
CA33	PLANNING & DESIGN AIDE			
CL012	SURVEY HELPER - ROD			
	1st 3 mos.	19.74	20.50	21.36
	Next 3 mos.	20.73	21.53	22.43
	Next 6 mos.	21.77	22.61	23.55
	Next 6 mos.	22.78	23.66	24.65
	Next 6 mos.	24.04	24.97	26.02
	Thereafter	25.32	26.29	27.40
TL286	FACILITY OPERATIONS LEAD MECHANIC			
	1st 3 mos.	22.78	23.66	24.65
	Next 3 mos.	24.04	24.97	26.02
	Next 6 mos.	25.32	26.29	27.40
	Thereafter	25.78	26.78	27.90

HAWAIIAN ELECTRIC COMPANY, INC.
EXHIBIT A
(continued)

JOB CODE	JOB TITLE	11/1/2007	1/1/2009	1/1/2010
TA08	UTILITY ASSISTANT			
TL215	UTILITY ASSISTANT			
T1011	UTILITY ASSISTANT			
	1st 12 mos.	25.20	26.18	27.27
	Thereafter	25.78	26.78	27.90
T337	TRUCK DRIVER C	25.78	26.78	27.90
T734	EQUIPMENT OPERATOR	26.54	27.56	28.72
T1021	STORES ATTENDANT			
	1st 3 mos.	14.45	15.01	15.64
	Next 3 mos.	15.91	16.52	17.21
	Next 6 mos.	17.50	18.18	18.94
	Next 6 mos.	19.31	20.06	20.90
	Next 6 mos.	21.24	22.06	22.98
	Next 6 mos.	23.41	24.32	25.33
	Next 6 mos.	25.78	26.78	27.90
	Thereafter	26.54	27.56	28.72
T1028	TRUCK DRIVER I			
	1st 12 mos.	25.78	26.78	27.90
	Thereafter	26.54	27.56	28.72
C883	RISK MANAGEMENT CLERK			
C1021	PAYMENT PROCESSING CLERK			
C1024	RECEIVING & FREIGHT CLERK			
C1025	JR DRAFTER			
T178	FIRE EQUIP INSP & RPR			
	1st 3 mos.	21.12	21.94	22.86
	Next 3 mos.	22.11	22.96	23.92
	Next 3 mos.	23.20	24.10	25.11
	Next 6 mos.	24.36	25.31	26.36
	Next 6 mos.	25.60	26.58	27.70
	Thereafter	26.87	27.91	29.08
CA09	TECHNICAL CLERK			
CD02	SAFETY AIDE			
C522	CONS ADV SERVICE CLERK			
C685	COMPUTER SYS OPERATOR			
	1st 9 mos.	24.16	25.11	26.16
	Next 9 mos.	25.51	26.50	27.61
	Thereafter	26.87	27.91	29.08
TA22	AUTO PARTS ATTENDANT			
	1st 6 mos.	23.66	24.57	25.60
	Next 6 mos.	24.85	25.81	26.89
	Next 6 mos.	26.09	27.10	28.24
	Thereafter	27.42	28.48	29.67
T224	UTILITY MECHANIC			
T732	SR WHSE ATTENDANT	27.42	28.48	29.67

HAWAIIAN ELECTRIC COMPANY, INC.
EXHIBIT A
(continued)

JOB CODE	JOB TITLE	11/1/2007	1/1/2009	1/1/2010
C369	ELECTRIC FACILITIES MANAGEMENT SYSTEM (EFMS) TECHNICIAN			
	1st 6 mos.	22.00	22.85	23.81
	Next 6 mos.	23.38	24.28	25.30
	Next 6 mos.	24.74	25.69	26.77
	Next 6 mos.	26.10	27.11	28.25
	Thereafter	27.50	28.56	29.76
CA38	JR CUSTOMER PLANNER			
	1st 9 mos.	24.74	25.69	26.77
	Next 6 mos.	26.10	27.11	28.25
	Thereafter	27.50	28.56	29.76
T114	(S) EQUIPMENT OPERATOR			
T286	TRUCK DRIVER II	27.85	28.93	30.14
CC04	JOB ACCOUNTING CLERK			
	1st 6 mos.	24.02	24.95	26.00
	Next 6 mos.	25.42	26.40	27.51
	Next 6 mos.	26.85	27.89	29.05
	Thereafter	28.27	29.36	30.59
CA02	CUSTOMER CLERK			
C614	ACCOUNTS PAYABLE & DISB CLK			
C646	PLANT ACCOUNTING CLERK			
C811	CUSTOMER FIELD REPRESENTATIVE			
C1019	MATERIAL COORDINATOR (T&D)			
C1020	CAPITAL BUDGETS AIDE			
	1st 3 mos.	21.20	22.02	22.94
	Next 3 mos.	22.59	23.47	24.45
	Next 3 mos.	24.02	24.95	26.00
	Next 6 mos.	25.42	26.40	27.51
	Next 6 mos.	26.85	27.89	29.05
	Thereafter	28.27	29.36	30.59
C619	CUSTOMER BILLING REPR			
C699	SR PRESS OPERATOR			
C810	CUSTOMER ACCOUNT SERVICES CLERK			
	1st 9 mos.	25.42	26.40	27.51
	Next 9 mos.	26.85	27.89	29.05
	Thereafter	28.27	29.36	30.59
CA44	DRAFTING TECHNICIAN I			
	1st 6 mos.	27.63	28.70	29.90
	Thereafter	29.09	30.22	31.48
T217	PAINTER			
	1st 12 mos.	24.67	25.63	26.70
	Next 12 mos.	27.07	28.11	29.29
	Next 12 mos.	28.59	29.69	30.93
	Thereafter	30.11	31.27	32.58

HAWAIIAN ELECTRIC COMPANY, INC.
EXHIBIT A
(continued)

JOB CODE	JOB TITLE	11/1/2007	1/1/2009	1/1/2010
CA18	EXPEDITER			
CA31	STATISTICAL CLERK			
C365	ENGRG OPERATIONS CLERK			
C1003	JOINT POLE COORDINATOR			
	1st 9 mos.	27.07	28.11	29.29
	Next 9 mos.	28.59	29.69	30.93
	Thereafter	30.11	31.27	32.58
C860	CUSTOMER ASSISTANCE REPR			
	1st 3 mos.	23.38	24.28	25.30
	Next 3 mos.	24.55	25.50	26.57
	Next 3 mos.	25.77	26.77	27.89
	Next 6 mos.	27.07	28.11	29.29
	Next 6 mos.	28.59	29.69	30.93
	Thereafter	30.11	31.27	32.58
C418	SR CUSTOMER FIELD INVESTIGATOR			
C420	SR CUSTOMER BILLING REPR			
	1st 9 mos.	27.72	28.79	29.99
	Next 9 mos.	29.28	30.41	31.68
	Thereafter	30.80	31.99	33.33
T219	CARPENTER			
	1st 12 mos.	24.67	25.63	26.70
	Next 12 mos.	26.87	27.91	29.08
	Next 12 mos.	29.36	30.50	31.77
	Thereafter	31.32	32.53	33.89
T221	MECHANIC			
T223	ELECTRICAL MECHANIC			
T263	AUTOMOTIVE MECHANIC			
	1st 12 mos.	29.36	30.50	31.77
	Thereafter	31.32	32.53	33.89
TA11	SR PAINTER			
T135	(S) UTILITY OPERATOR			
T173	MAINT EQUIP MECHANIC			
T236	DISTR LINE INSPECTOR			
T308	INSPECTOR			
T1015	SR FIRE EQUIP INSP & RPR	31.32	32.53	33.89
C461	LEAD CUSTOMER ASSISTANCE REPR			
C622	SR COMPUTER SYSTEMS OPER			
C1022	LEAD PYMNT PROC & SUPP CTR CLK			
	1st 9 mos.	28.59	29.69	30.93
	Next 9 mos.	30.20	31.37	32.68
	Thereafter	31.76	32.99	34.37
C013	CUSTOMER PLANNER			
	1st 9 mos.	28.69	29.80	31.05
	Next 9 mos.	30.25	31.42	32.74
	Thereafter	31.87	33.10	34.48

HAWAIIAN ELECTRIC COMPANY, INC.
EXHIBIT A
(continued)

JOB CODE	JOB TITLE	11/1/2007	1/1/2009	1/1/2010
C026	TRANSIT TECHNICIAN			
C1009	SR ELECTRIC FACILITIES MANAGEMENT SYSTEM (EFMS) TECHNICIAN			
	1st 9 mos.	29.49	30.63	31.91
	Next 9 mos.	31.16	32.37	33.72
	Thereafter	32.77	34.03	35.46
CA15	DRAFTING TECH II			
C1012	DRAFTING TECH II			
	1st 12 mos.	29.83	30.98	32.28
	Next 12 mos.	30.73	31.92	33.25
	Next 12 mos.	31.72	32.95	34.33
	Thereafter	32.77	34.03	35.46
T1008	TOOL ROOM UTILITY MECHANIC			
	1st 12 mos.	30.11	31.27	32.58
	Thereafter	32.82	34.09	35.52
T325	(S) TROUBLEMAN			
	1st 12 mos.	31.32	32.53	33.89
	Thereafter	32.82	34.09	35.52
TA12	SR CARPENTER			
T158	MOBILE CRANE & HVY EQUIP OPER			
T165	MAINT EQUIP SPECIALIST			
T259	REFINISHER			
T285	TOOL ROOM SPECIALIST			
T287	UTILITY MECHANIC			
T735	MOBILE CRANE & HVY EQUIP OPER			
T737	RECEIVING COORDINATOR	32.82	34.09	35.52
T131	INSULATOR			
	1st 12 mos.	24.67	25.63	26.70
	Next 12 mos.	26.87	27.91	29.08
	Next 12 mos.	28.50	29.61	30.84
	Next 12 mos.	30.11	31.27	32.58
	Thereafter	33.51	34.81	36.27
T1019	CONSTRUCTION JOURNEYMAN			
	1st 12 mos.	25.20	26.18	27.27
	Next 12 mos.	26.87	27.91	29.08
	Next 12 mos.	28.50	29.61	30.84
	Next 12 mos.	30.11	31.27	32.58
	Thereafter	33.51	34.81	36.27
T121	ELECTRICIAN			
T127	BOILER MECHANIC			
T129	WELDER 1/C			
T227	ELECTRICIAN			
T310	ELECTRICIAN (RELAY)			
T324	ELECTRICIAN (COMM)			
T331	ELECTRICIAN (I&C)			
T1004	CONTROL MECHANIC			
T1007	MACHINIST MECHANIC			
T1026	ELECTRICIAN			
	1st 12 mos.	30.11	31.27	32.58
	Thereafter	33.51	34.81	36.27

HAWAIIAN ELECTRIC COMPANY, INC.
EXHIBIT A
(continued)

JOB CODE	JOB TITLE	11/1/2007	1/1/2009	1/1/2010
T298	WELDER/MACHINIST			
T311	PRIMARY INSPECTOR			
T1023	LEAD UTILITY MECHANIC	33.51	34.81	36.27
T149	(S) JR CONTROL OPERATOR	33.68	34.98	36.44
T276	SUBSTATION ELECTRICIAN			
	1st 3 mos.	23.57	24.48	25.50
	Next 3 mos.	24.93	25.90	26.98
	Next 3 mos.	25.96	26.96	28.09
	Next 6 mos.	26.98	28.03	29.20
	Next 6 mos.	28.01	29.09	30.31
	Next 6 mos.	29.03	30.15	31.42
	Next 12 mos.	31.32	32.53	33.89
	Thereafter	34.16	35.48	36.96
T229	LINEMAN			
T288	CREW DISPATCHER			
	1st 12 mos.	31.32	32.53	33.89
	Thereafter	34.16	35.48	36.96
T309	SR METER ELECTRICIAN			
	1st 6 mos.	28.01	29.09	30.31
	Next 6 mos.	29.03	30.15	31.42
	Next 12 mos.	31.32	32.53	33.89
	Next 12 mos.	32.82	34.09	35.52
	Thereafter	34.16	35.48	36.96
TA04	CERT AUTOMOTIVE MECHANIC			
TA13	CERT WELDER/MACHINST			
T125	MACHINIST			
T137	CERT COMBINATION WELDER			
T174	SR ELECTRICIAN			
T175	PIPEFITTER MECHANIC			
T185	CERT EQUIPMENT MECHANIC			
T291	CABLE SPLICER			
T299	SR ELECTRICIAN			
T343	SR ELECTRICIAN (RELAY)			
T344	SR ELECTRICIAN (COMM)			
T345	SR ELECTRICIAN (I&C)			
T1005	SR CONTROL MECHANIC			
T1027	SR ELECTRICIAN	34.16	35.48	36.96
T1000	LEAD WAREHOUSE ATTENDANT	34.33	35.66	37.15
T314	TECHNICIAN (RELAY)			
T327	TECHNICIAN (COMM)			
T332	TECHNICIAN (I&C)			
T1006	CONTROL TECHNICIAN	34.69	36.03	37.54

HAWAIIAN ELECTRIC COMPANY, INC.
EXHIBIT A
(continued)

JOB CODE		JOB TITLE	11/1/2007	1/1/2009	1/1/2010
CF19		DRAFTING TECHNICIAN III			
C081		DRAFTING TECHNICIAN III			
		1st 12 mos.	33.68	34.98	36.44
		Thereafter	34.81	36.15	37.67
T312	(S)	PRIMARY TROUBLEMAN			
		1st 12 mos.	34.16	35.48	36.96
		Thereafter	34.81	36.15	37.67
T235		SR CABLE SPLICER			
T273		SUBSTATION INSPECTOR	34.81	36.15	37.67
T1029		T&D INSPECTOR			
T1024		CONSTRUCTION INSPECTOR			
		1st 12 mos.	34.16	35.48	36.96
		Thereafter	35.31	36.68	38.21
T154	(S)	CONTROL OPERATOR			
T241		SUBSTATION TECHNICIAN			
T268		AERIAL LINEMAN			
T315	(S)	TROUBLE DISPATCHER			
T1013	(S)	SR PRIMARY TROUBLEMAN			
T1020		T&D PRE-ASSEMBLER	35.31	36.68	38.21
TA01		LEAD CABLE SPLICER	35.96	37.35	38.91
CA77		DESIGN PLANNER			
		1st 9 mos.	33.20	34.49	35.93
		Next 9 mos.	35.03	36.39	37.91
		Thereafter	36.89	38.31	39.92
CA07		DESIGN DRAFTING TECH			
CF20		DESIGN DRAFTING TECH			
		1st 12 mos.	35.83	37.22	38.77
		Thereafter	36.89	38.31	39.92
F155		WORKING FOREMAN			
F248		WORKING FOREMAN			
F338		WORKING FOREMAN			
F713		WORKING FOREMAN (STORES)			
F736		WORKING FOREMAN (CONSTR)			
F737		WORKING FOREMAN			
F738		WORKING FOREMAN			
T316	(S)	LOAD DISPATCHER	36.91	38.33	39.94
F249		FOREMAN	39.24	40.75	42.46

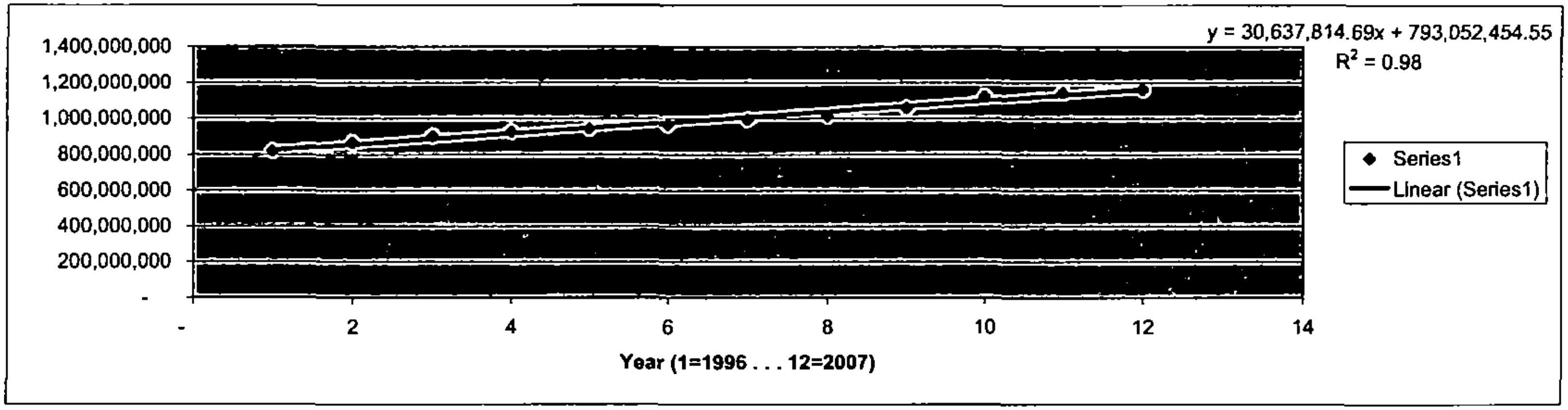
Attachments 7A through 8C contain confidential information and are provided subject to the Protective Order filed on January 6, 2009 in this proceeding.

HECO [illegible] Base Regression

Year	t	HECO Simple Avg Rate Base
1996	1	818,276,000
1997	2	864,771,000
1998	3	899,527,000
1999	4	924,688,000
2000	5	941,817,000
2001	6	965,566,000
2002	7	993,499,000
2003	8	1,011,420,000
2004	9	1,058,206,000
2005	10	1,121,604,000
2006	11	1,144,768,000
2007	12	1,162,237,000

PREDICTED	Year	t	
	2008	13	1,191,344,000
	2009	14	1,221,982,000
	2010	15	1,252,620,000
	2011	16	1,283,257,000
	2012	17	1,313,895,000
	2013	18	1,344,533,000

INTERCEPT	793,052,454.55
SLOPE	30,637,814.69



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.991490681
R Square	0.983053771
Adjusted R Square	0.981359148
Standard Error	15211558.31
Observations	12

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1.34231E+17	1.34231E+17	580.1017752	3.46382E-10
Residual	10	2.31392E+15	2.31392E+14		
Total	11	1.36545E+17			

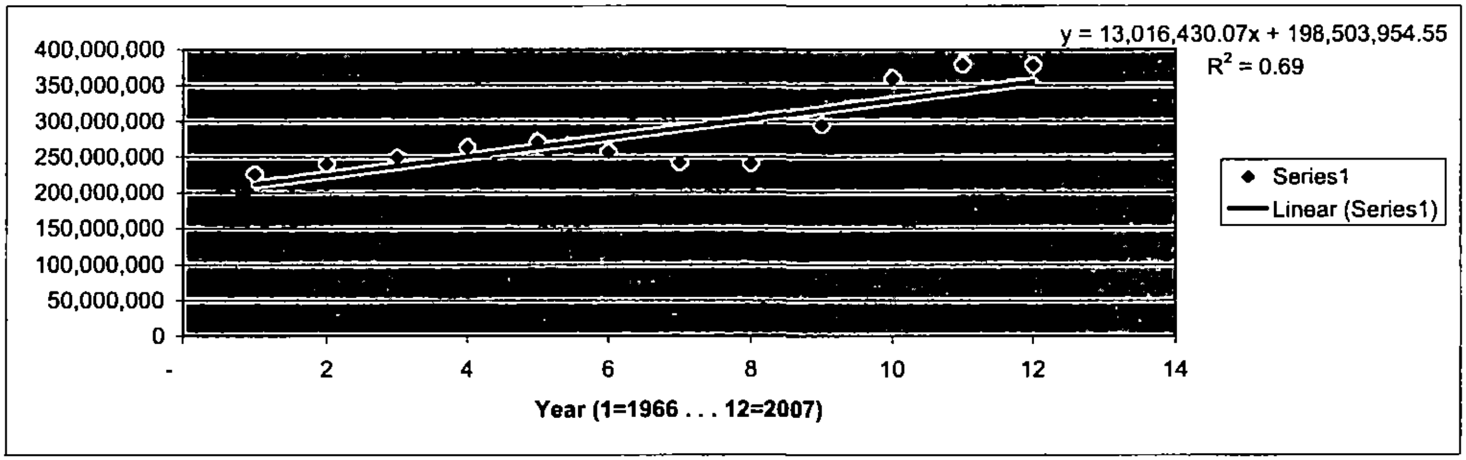
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	793,052,454.55	9362066.961	84.7091201	1.28537E-15	772192469.5	813912439.6	772192469.5	813912439.6
X Variable 1	30,637,814.69	1272054.409	24.08530206	3.46382E-10	27803500.85	33472128.52	27803500.85	33472128.52

HELCO [illegible] Base Regression

	t	HELCO Simple Ave Rate Base
1996	1	226,319,000
1997	2	240,321,000
1998	3	249,447,000
1999	4	263,198,000
2000	5	270,798,000
2001	6	256,241,000
2002	7	241,576,000
2003	8	240,281,000
2004	9	294,091,000
2005	10	358,815,000
2006	11	378,695,000
2007	12	377,547,000

PREDICTED	Year	t	
	2008	13	367,718,000
	2009	14	380,734,000
	2010	15	393,750,000
	2011	16	406,767,000
	2012	17	419,783,000
	2013	18	432,800,000

INTERCEPT 198,503,954.55
SLOPE 13,016,430.07



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.832893063
R Square	0.693710855
Adjusted R Square	0.66308194
Standard Error	32706680.34
Observations	12

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2.42281E+16	2.42281E+16	22.64888798	0.00076961
Residual	10	1.06973E+16	1.06973E+15		
Total	11	3.49254E+16			

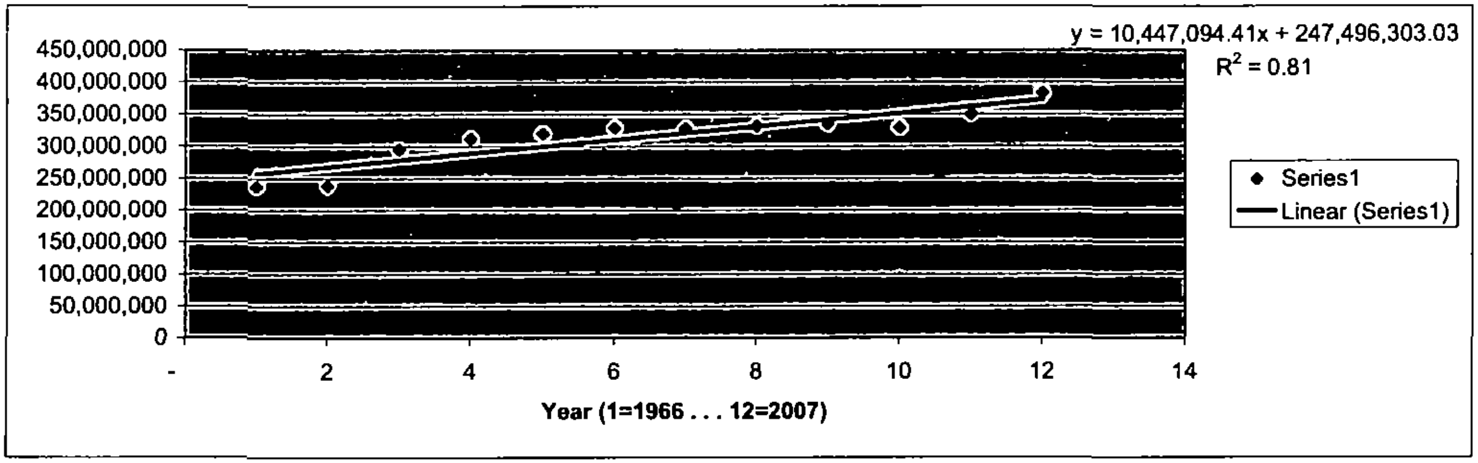
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	198,503,954.55	20129570.24	9.861311105	1.80636E-06	153652477.2	243355431.9	153652477.2	243355431.9
X Variable 1	13,016,430.07	2735070.011	4.759084784	0.00076961	6922314.342	19110545.8	6922314.342	19110545.8

MECO [illegible] Base Regression

	t	MECO Simple Ave Rate Base
1996	1	237,585,000
1997	2	238,237,000
1998	3	294,705,000
1999	4	311,664,000
2000	5	319,511,000
2001	6	328,549,000
2002	7	327,503,000
2003	8	331,290,000
2004	9	334,190,000
2005	10	328,901,000
2006	11	350,245,000
2007	12	382,449,000

PREDICTED	Year	t	
	2008	13	383,309,000
	2009	14	393,756,000
	2010	15	404,203,000
	2011	16	414,650,000
	2012	17	425,097,000
	2013	18	435,544,000

INTERCEPT	247,496,303.03
SLOPE	10,447,094.41



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.899599557
R Square	0.809279362
Adjusted R Square	0.790207298
Standard Error	19178434.36
Observations	12

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1.56073E+16	1.56073E+16	42.43271056	6.77385E-05
Residual	10	3.67812E+15	3.67812E+14		
Total	11	1.92854E+16			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	247,496,303.03	11803510.4	20.96802516	1.3513E-09	221196443	273796163	221196443	273796163
X Variable 1	10,447,094.41	1603781.25	6.514039496	6.77385E-05	6873647.108	14020541.7	6873647.108	14020541.7

DOCKET NO. 2008-0274
ATTACHMENT 9C
PAGE 1 OF 1

Attachments 10A, 10B, and 10C contain confidential information and are provided subject to the Protective Order filed on January 6, 2009 in this proceeding.

Waiau fuel pipeline, in-svc 12/04 (Dkt.No. 01-0444)	Capital Cost, per Completion Report	Depreciation Expense	Depreciation Reserve	ADIT	Net Plant Adds for Project	Average Rate Base Reduction
	(a)	(b)	(c) = (c)prev+(b)	(d)	(e) = (a) - (c) - (d)	((e)prev + (e)curr)/2
1996			$ -		$ -	$ -
1997			$ -		$ -	$ -
1998			$ -		$ -	$ -
1999			$ -		$ -	$ -
2000			$ -		$ -	$ -
2001			$ -		$ -	$ -
2002			$ -		$ -	$ -
2003			$ -		$ -	$ -
2004	$ 40,622,000		$ -	$ 845,622	$ 39,776,378	**$ 19,888,189**
2005	$ 40,622,000	$ 673,960	$ 673,960	$ 1,715,991	$ 38,232,049	**$ 39,004,214**
2006	$ 40,622,000	$ 673,960	$ 1,347,919	$ 2,500,691	$ 36,773,390	**$ 37,502,720**
2007	$ 40,622,000	$ 673,960	$ 2,021,879	$ 3,206,361	$ 35,393,760	**$ 36,083,575**

* Major projects are defined as $20M or more for HECO; $10M or more for HELCO and MECO.

Kewalo transformers A & B, in-svc 2/03 (Dkt. No. 7526)	Capital Cost, per Completion Report	Depreciation Expense	Depreciation Reserve	ADIT	Net Plant Adds for Project	Average Rate Base Reduction
	(a)	(b)	(c) = (c)prev+(b)	(d)	(e) = (a) - (c) - (d)	((e)prev + (e)curr)/2
1996			$ -		$ -	$ -
1997			$ -		$ -	$ -
1998			$ -		$ -	$ -
1999			$ -		$ -	$ -
2000			$ -		$ -	$ -
2001			$ -		$ -	$ -
2002			$ -		$ -	$ -
2003	$ 37,895,000		$ -	$ 552,936	$ 37,342,064	**$ 18,671,032**
2004	$ 37,895,000	$ 1,103,427	$ 1,103,427	$ 1,188,030	$ 35,603,543	**$ 36,472,804**
2005	$ 37,895,000	$ 1,103,427	$ 2,206,853	$ 1,743,206	$ 33,944,941	**$ 34,774,242**
2006	$ 37,895,000	$ 1,103,427	$ 3,310,280	$ 2,224,658	$ 32,360,062	**$ 33,152,501**
2007	$ 37,895,000	$ 1,103,427	$ 4,413,706	$ 2,637,693	$ 30,843,601	**$ 31,601,831**

* Major projects are defined as $20M or more for HECO; $10M or more for HELCO and MECO.

Kewalo-Kamoku transmission, In-svc 9/02 (Dkt. No. 7602)	Capital Cost, per Completion Report	Depreciation Expense	Depreciation Reserve	ADIT	Net Plant Adds for Project	Average Rate Base Reduction
	(a)	(b)	(c) = (c)prev+(b)	(d)	(e) = (a) - (c) - (d)	((e)prev + (e)curr)/2
1996			$ -		$ -	$ -
1997			$ -		$ -	$ -
1998			$ -		$ -	$ -
1999			$ -		$ -	$ -
2000			$ -		$ -	$ -
2001			$ -		$ -	$ -
2002	$ 49,084,000		$ -	$ 716,197	$ 48,367,803	**$ 24,183,902**
2003	$ 49,084,000	$ 1,429,228	$ 1,429,228	$ 1,538,811	$ 46,115,961	**$ 47,241,882**
2004	$ 49,084,000	$ 1,429,228	$ 2,858,456	$ 2,257,911	$ 43,967,633	**$ 45,041,797**
2005	$ 49,084,000	$ 1,429,228	$ 4,287,684	$ 2,881,518	$ 41,914,798	**$ 42,941,216**
2006	$ 49,084,000	$ 1,429,228	$ 5,716,912	$ 3,416,508	$ 39,950,580	**$ 40,932,689**
2007	$ 49,084,000	$ 1,429,228	$ 7,146,140	$ 3,869,755	$ 38,068,105	**$ 39,009,343**

* Major projects are defined as $20M or more for HECO; $10M or more for HELCO and MECO.

Iwilei transformers, in-svc 6/98 (Dkt. No. 7535)	Capital Cost, per Completion Report	Depreciation Expense	Depreciation Reserve	ADIT	Net Plant Adds for Project	Average Rate Base Reduction
	(a)	(b)	(c) = (c)prev+(b)	(d)	(e) = (a) - (c) - (d)	((e)prev + (e)curr)/2
1996			$ -		$ -	$ -
1997			$ -		$ -	$ -
1998	$ 20,955,000		$ -	$ 305,760	$ 20,649,240	$ 10,324,620
1999	$ 20,955,000	$ 610,168	$ 610,168	$ 656,951	$ 19,687,881	$ 20,168,561
2000	$ 20,955,000	$ 610,168	$ 1,220,335	$ 963,950	$ 18,770,715	$ 19,229,298
2001	$ 20,955,000	$ 610,168	$ 1,830,503	$ 1,230,181	$ 17,894,316	$ 18,332,515
2002	$ 20,955,000	$ 610,168	$ 2,440,671	$ 1,458,579	$ 17,055,750	$ 17,475,033
2003	$ 20,955,000	$ 610,168	$ 3,050,838	$ 1,652,080	$ 16,252,082	$ 16,653,916
2004	$ 20,955,000	$ 610,168	$ 3,661,006	$ 1,813,211	$ 15,480,783	$ 15,866,432
2005	$ 20,955,000	$ 610,168	$ 4,271,174	$ 1,944,500	$ 14,739,326	$ 15,110,055
2006	$ 20,955,000	$ 610,168	$ 4,881,342	$ 2,070,897	$ 14,002,761	$ 14,371,044
2007	$ 20,955,000	$ 610,168	$ 5,491,509	$ 2,197,212	$ 13,266,279	$ 13,634,520

* Major projects are defined as $20M or more for HECO; $10M or more for HELCO and MECO.

Dispatch Center, in-svc 12/06 (Dkt. No. 03-0360)	Capital Cost, per Completion Report	Depreciation Expense	Depreciation Reserve	ADIT	Net Plant Adds for Project	Average Rate Base Reduction
	(a)	(b)	(c) = (c)prev+(b)	(d)	(e) = (a) - (c) - (d)	((e)prev + (e)curr)/2
1996			$ -		$ -	$ -
1997			$ -		$ -	$ -
1998			$ -		$ -	$ -
1999			$ -		$ -	$ -
2000			$ -		$ -	$ -
2001			$ -		$ -	$ -
2002			$ -		$ -	$ -
2003			$ -		$ -	$ -
2004			$ -		$ -	$ -
2005			$ -		$ -	$ -
2006	$ 27,204,000		$ -	$ 11,326	$ 27,192,674	$ 13,596,337
2007	$ 27,204,000	$ 1,430,005	$ 1,430,005	$ (273,687)	$ 26,047,682	$ 26,620,178

* Major projects are defined as $20M or more for HECO; $10M or more for HELCO and MECO.

HECO SIGNIFICANT PROJECTS, TOTAL	Total Capital Cost, per Completion Reports	Total Depreciation Expense	Total Depreciation Reserve	Total ADIT	Total Net Plant Adds	Average Rate Base Reduction
	(a)	(b)	(c) = (c)prev+(b)	(d)	(e) = (a) - (c) - (d)	((e)prev + (e)curr)/2
1996	$ -	$ -	$ -	$ -	$ -	$ -
1997	$ -	$ -	$ -	$ -	$ -	$ -
1998	$ 20,955,000	$ -	$ -	$ 305,760	$ 20,649,240	$ 10,324,620
1999	$ 20,955,000	$ 610,168	$ 610,168	$ 656,951	$ 19,687,881	$ 20,168,561
2000	$ 20,955,000	$ 610,168	$ 1,220,335	$ 963,950	$ 18,770,715	$ 19,229,298
2001	$ 20,955,000	$ 610,168	$ 1,830,503	$ 1,230,181	$ 17,894,316	$ 18,332,515
2002	$ 70,039,000	$ 610,168	$ 2,440,671	$ 2,174,776	$ 65,423,553	$ 41,658,935
2003	$ 107,934,000	$ 2,039,396	$ 4,480,066	$ 3,743,827	$ 99,710,107	$ 82,566,830
2004	$ 148,556,000	$ 3,142,822	$ 7,622,889	$ 6,104,774	$ 134,828,337	$ 117,269,222
2005	$ 148,556,000	$ 3,816,782	$ 11,439,670	$ 8,285,215	$ 128,831,115	$ 131,829,726
2006	$ 175,760,000	$ 3,816,782	$ 15,256,452	$ 10,224,080	$ 150,279,468	$ 139,555,291
2007	$ 175,760,000	$ 5,246,787	$ 20,503,239	$ 11,637,334	$ 143,619,427	$ 146,949,447

* Major projects are defined as $20M or more for HECO; $10M or more for HELCO and MECO.

DOCKET NO. 2008-0274
ATTACHMENT 11A
PAGE 2 OF 2

HELCO major projects

HELCO SIGNIFICANT PROJECTS, TOTAL	Keahole CT-4 and CT-5, 5/04 (7048, 7623) **	Depreciation Expense	Depreciation Reserve	ADIT	Net Plant Adds for Project	Average Rate Base Reduction
	(a)	(b)	(c) = (c)prev+(b)	(d)	(e) = (a) - (c) - (d)	((e)prev + (e)curr)/2
1996			$ -		$ -	$ -
1997			$ -		$ -	$ -
1998			$ -		$ -	$ -
1999			$ -		$ -	$ -
2000			$ -		$ -	$ -
2001			$ -		$ -	$ -
2002			$ -		$ -	$ -
2003			$ -		$ -	$ -
2004	$ 117,609,000		$ -	$ 6,345,000	$ 111,264,000	**$ 55,632,000**
2005	$ 104,711,000	$ 4,707,000	$ 4,707,000	$ 7,404,000	$ 92,600,000	**$ 101,932,000**
2006	$ 104,711,000	$ 5,022,000	$ 9,729,000	$ 7,944,000	$ 87,038,000	**$ 89,819,000**
2007	$ 104,711,000	$ 5,022,000	$ 14,751,000	$ 8,294,000	$ 81,666,000	**$ 84,352,000**

* Major projects are defined as $20M or more for HECO; $10M or more for HELCO and MECO.

** 2004: Per Docket No. 05-0315, HELCO-RT-1 (revised 4-30-08)
2005-2007: 2004 less $12,898,000 gross plant in service adjustment per settlement agreement, Docket No. 05-0315

Maalaea M18, in-svc 10/06 (Dkt. No. 7744)	Total Capital Cost, per Completion Report	Depreciation Expense	Depreciation Reserve	ADIT	Net Plant Adds for Project	Average Rate Base Reduction
	(a)	(b)	(c) = (c)prev+(b)	(d)	(e) = (a) - (c) - (d)	((e)prev + (e)curr)/2
1996			$ -		$ -	$ -
1997			$ -		$ -	$ -
1998			$ -		$ -	$ -
1999			$ -		$ -	$ -
2000			$ -		$ -	$ -
2001			$ -		$ -	$ -
2002			$ -		$ -	$ -
2003			$ -		$ -	$ -
2004			$ -		$ -	$ -
2005			$ -		$ -	$ -
2006	$ 64,811,000	$ -	$ -	$ 945,668	$ 63,865,332	$ 31,932,666
2007	$ 64,811,000	$ 1,069,382	$ 1,069,382	$ 2,350,048	$ 61,391,571	$ 62,628,451

* Major projects are defined as $20M or more for HECO; $10M or more for HELCO and MECO.

Maalaea DTCC No. 2- M19, in-svc 9/00 (Dkt. No. 7744)	Total Capital Cost, per Completion Report	Depreciation Expense	Depreciation Reserve	ADIT	Net Plant Adds for Project	Average Rate Base Reduction
	(a)	(b)	(c) = (c)prev+(b)	(d)	(e) = (a) - (c) - (d)	((e)prev + (e)curr)/2
1996			$ -		$ -	$ -
1997			$ -		$ -	$ -
1998			$ -		$ -	$ -
1999			$ -		$ -	$ -
2000	$ 24,628,000	$ -	$ -	$ 479,135	$ 24,148,865	$ 12,074,433
2001	$ 24,628,000	$ 1,059,004	$ 1,059,004	$ 977,435	$ 22,591,561	$ 23,370,213
2002	$ 24,628,000	$ 1,059,004	$ 2,118,008	$ 1,384,700	$ 21,125,292	$ 21,858,427
2003	$ 24,628,000	$ 1,059,004	$ 3,177,012	$ 1,710,512	$ 19,740,476	$ 20,432,884
2004	$ 24,628,000	$ 1,059,004	$ 4,236,016	$ 1,962,537	$ 18,429,447	$ 19,084,962
2005	$ 24,628,000	$ 1,059,004	$ 5,295,020	$ 2,147,483	$ 17,185,497	$ 17,807,472
2006	$ 24,628,000	$ 1,059,004	$ 6,354,024	$ 2,300,806	$ 15,973,170	$ 16,579,334
2007	$ 24,628,000	$ 1,059,004	$ 7,413,028	$ 2,454,129	$ 14,760,843	$ 15,367,007

* Major projects are defined as $20M or more for HECO; $10M or more for HELCO and MECO.

Maalaea DTCC No. 2 - M17, in-svc 12/98 (Dkt. No. 7744)	Total Capital Cost, per Completion Report	Depreciation Expense	Depreciation Reserve	ADIT	Net Plant Adds for Project	Average Rate Base Reduction
	(a)	(b)	(c) = (c)prev+(b)	(d)	(e) = (a) - (c) - (d)	((e)prev + (e)curr)/2
1996			$ -		$ -	$ -
1997			$ -		$ -	$ -
1998	$ 57,121,000	$ -	$ -	$ 1,111,283	$ 56,009,717	$ 28,004,859
1999	$ 57,121,000	$ 2,536,172	$ 2,536,172	$ 2,235,901	$ 52,348,927	$ 54,179,322
2000	$ 57,121,000	$ 2,536,172	$ 5,072,345	$ 3,149,376	$ 48,899,279	$ 50,624,103
2001	$ 57,121,000	$ 2,536,172	$ 7,608,517	$ 3,873,932	$ 45,638,551	$ 47,268,915
2002	$ 57,121,000	$ 2,536,172	$ 10,144,690	$ 4,427,351	$ 42,548,959	$ 44,093,755
2003	$ 57,121,000	$ 2,536,172	$ 12,680,862	$ 4,825,190	$ 39,614,948	$ 41,081,954
2004	$ 57,121,000	$ 2,536,172	$ 15,217,034	$ 5,149,685	$ 36,754,281	$ 38,184,614
2005	$ 57,121,000	$ 2,536,172	$ 17,753,207	$ 5,474,180	$ 33,893,613	$ 35,323,947
2006	$ 57,121,000	$ 2,536,172	$ 20,289,379	$ 5,800,897	$ 31,030,724	$ 32,462,169
2007	$ 57,121,000	$ 2,536,172	$ 22,825,552	$ 6,125,392	$ 28,170,056	$ 29,600,390

* Major projects are defined as $20M or more for HECO; $10M or more for HELCO and MECO.

Palaau Units 7 through 9, In-svc 1996 (Dkt No. 7710)	Total Capital Cost, per Completion Report	Depreciation Expense	Depreciation Reserve	ADIT	Net Plant Adds for Project	Average Rate Base Reduction
	(a)	(b)	(c) = (c)prev+(b)	(d)	(e) = (a) - (c) - (d)	((e)prev + (e)curr)/2
1996	$ 18,201,599	$ -	$ -	$ 354,110	$ 17,847,489	$ 8,923,745
1997	$ 18,201,599	$ 728,064	$ 728,064	$ 743,631	$ 16,729,904	$ 17,288,697
1998	$ 18,201,599	$ 728,064	$ 1,456,128	$ 1,065,871	$ 15,679,600	$ 16,204,752
1999	$ 18,201,599	$ 728,064	$ 2,184,192	$ 1,327,912	$ 14,689,495	$ 15,184,548
2000	$ 18,201,599	$ 728,064	$ 2,912,256	$ 1,535,421	$ 13,753,922	$ 14,221,709
2001	$ 18,201,599	$ 728,064	$ 3,640,320	$ 1,693,354	$ 12,867,925	$ 13,310,924
2002	$ 18,201,599	$ 728,064	$ 4,368,384	$ 1,827,916	$ 12,005,299	$ 12,436,612
2003	$ 18,201,599	$ 728,064	$ 5,096,448	$ 1,962,478	$ 11,142,673	$ 11,573,986
2004	$ 18,201,599	$ 728,064	$ 5,824,512	$ 2,097,748	$ 10,279,339	$ 10,711,006
2005	$ 18,201,599	$ 728,064	$ 6,552,576	$ 2,232,310	$ 9,416,713	$ 9,848,026
2006	$ 18,201,599	$ 728,064	$ 7,280,640	$ 2,367,580	$ 8,553,379	$ 8,985,046
2007	$ 18,201,599	$ 728,064	$ 8,008,704	$ 2,502,142	$ 7,690,753	$ 8,122,066

* Major projects are defined as $20M or more for HECO; $10M or more for HELCO and MECO.

Miki Basin General Expansion, In-svc 10/15/96	Total Capital Cost, per Completion Report	Depreciation Expense	Depreciation Reserve	ADIT	Net Plant Adds for Project	Average Rate Base Reduction
	(a)	(b)	(c) = (c)prev+(b)	(d)	(e) = (a) - (c) - (d)	((e)prev + (e)curr)/2
1996	$ 13,301,744	$ -	$ -	$ 258,784	$ 13,042,960	$ 6,521,480
1997	$ 13,301,744	$ 691,691	$ 691,691	$ 481,338	$ 12,128,715	$ 12,585,838
1998	$ 13,301,744	$ 691,691	$ 1,383,381	$ 654,723	$ 11,263,640	$ 11,696,177
1999	$ 13,301,744	$ 691,691	$ 2,075,072	$ 784,115	$ 10,442,557	$ 10,853,098
2000	$ 13,301,744	$ 691,691	$ 2,766,763	$ 873,654	$ 9,661,327	$ 10,051,942
2001	$ 13,301,744	$ 691,691	$ 3,458,453	$ 926,964	$ 8,916,327	$ 9,288,827
2002	$ 13,301,744	$ 691,691	$ 4,150,144	$ 963,194	$ 8,188,406	$ 8,552,366
2003	$ 13,301,744	$ 691,691	$ 4,841,835	$ 999,424	$ 7,460,485	$ 7,824,446
2004	$ 13,301,744	$ 691,691	$ 5,533,526	$ 1,036,171	$ 6,732,047	$ 7,096,266
2005	$ 13,301,744	$ 691,691	$ 6,225,216	$ 1,072,401	$ 6,004,127	$ 6,368,087
2006	$ 13,301,744	$ 691,691	$ 6,916,907	$ 1,109,148	$ 5,275,689	$ 5,639,908
2007	$ 13,301,744	$ 691,691	$ 7,608,598	$ 1,145,378	$ 4,547,768	$ 4,911,729

* Major projects are defined as $20M or more for HECO; $10M or more for HELCO and MECO.

Maalaea-Lahaina Third 69kV Line, In-svc 12/6/96 (Dkt No.	Total Capital Cost, per Completion Report	Depreciation Expense	Depreciation Reserve	ADIT	Net Plant Adds for Project	Average Rate Base Reduction
	(a)	(b)	(c) = (c)prev+(b)	(d)	(e) = (a) - (c) - (d)	((e)prev + (e)curr)/2
1996	$ 20,182,243	$ -	$ -	$ 294,482	$ 19,887,761	$ 9,943,881
1997	$ 20,182,243	$ 666,014	$ 666,014	$ 602,236	$ 18,913,993	$ 19,400,877
1998	$ 20,182,243	$ 666,014	$ 1,332,028	$ 867,427	$ 17,982,788	$ 18,448,390
1999	$ 20,182,243	$ 666,014	$ 1,998,042	$ 1,093,354	$ 17,090,847	$ 17,536,817
2000	$ 20,182,243	$ 666,014	$ 2,664,056	$ 1,282,844	$ 16,235,343	$ 16,663,095
2001	$ 20,182,243	$ 666,014	$ 3,330,070	$ 1,438,724	$ 15,413,449	$ 15,824,396
2002	$ 20,182,243	$ 666,014	$ 3,996,084	$ 1,563,427	$ 14,622,732	$ 15,018,090
2003	$ 20,182,243	$ 666,014	$ 4,662,098	$ 1,659,389	$ 13,860,756	$ 14,241,744
2004	$ 20,182,243	$ 666,014	$ 5,328,112	$ 1,750,639	$ 13,103,492	$ 13,482,124
2005	$ 20,182,243	$ 666,014	$ 5,994,126	$ 1,841,811	$ 12,346,306	$ 12,724,899
2006	$ 20,182,243	$ 666,014	$ 6,660,140	$ 1,933,061	$ 11,589,042	$ 11,967,674
2007	$ 20,182,243	$ 666,014	$ 7,326,154	$ 2,024,233	$ 10,831,856	$ 11,210,449

* Major projects are defined as $20M or more for HECO; $10M or more for HELCO and MECO.

MECO SIGNIFICANT PROJECTS, TOTAL	Total Capital Cost, per Completion Reports	Total Depreciation Expense	Total Depreciation Reserve	Total ADIT	Total Net Plant Adds	Average Rate Base Reduction
		(b)	(c) = (c)prev+(b)	(d)	(e) = (a) - (c) - (d)	((e)prev + (e)curr)/2
1996	$ 51,685,586	$ -	$ -	$ 907,376	$ 50,778,210	**$ 25,389,105**
1997	$ 51,685,586	$ 2,085,769	$ 2,085,769	$ 1,827,205	$ 47,772,612	**$ 49,275,411**
1998	$ 108,806,586	$ 2,085,769	$ 4,171,537	$ 3,699,304	$ 100,935,745	**$ 74,354,178**
1999	$ 108,806,586	$ 4,621,941	$ 8,793,478	$ 5,441,282	$ 94,571,826	**$ 97,753,785**
2000	$ 133,434,586	$ 4,621,941	$ 13,415,419	$ 7,320,430	$ 112,698,737	**$ 103,635,281**
2001	$ 133,434,586	$ 5,680,945	$ 19,096,365	$ 8,910,409	$ 105,427,812	**$ 109,063,274**
2002	$ 133,434,586	$ 5,680,945	$ 24,777,310	$ 10,166,588	$ 98,490,688	**$ 101,959,250**
2003	$ 133,434,586	$ 5,680,945	$ 30,458,255	$ 11,156,993	$ 91,819,338	**$ 95,155,013**
2004	$ 133,434,586	$ 5,680,945	$ 36,139,200	$ 11,996,780	$ 85,298,606	**$ 88,558,972**
2005	$ 133,434,586	$ 5,680,945	$ 41,820,145	$ 12,768,185	$ 78,846,256	**$ 82,072,431**
2006	$ 198,245,586	$ 5,680,945	$ 47,501,090	$ 14,457,160	$ 136,287,336	**$ 107,566,796**
2007	$ 198,245,586	$ 6,750,327	$ 54,251,416	$ 16,601,322	$ 127,392,848	**$ 131,840,092**

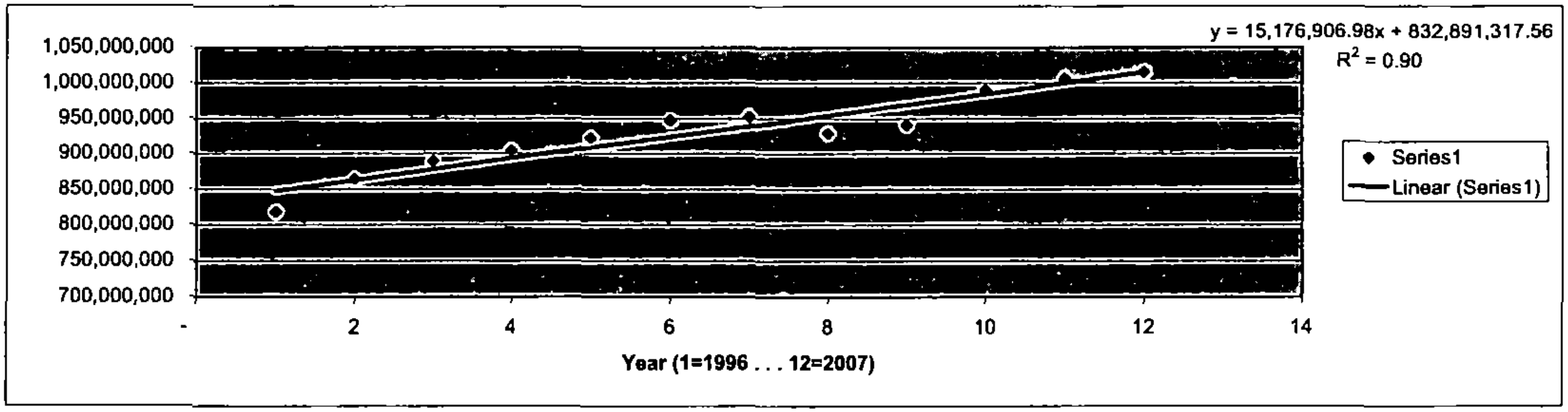
* Major projects are defined as $20M or more for HECO; $10M or more for HELCO and MECO.

HECO R[illegible]ss_wo major projects

Year	t	HECO Avg Rate Base, less major projects net of dep, ADIT
1996	1	818,276,000
1997	2	864,771,000
1998	3	889,202,380
1999	4	904,519,439
2000	5	922,587,702
2001	6	947,233,485
2002	7	951,840,065
2003	8	928,853,170
2004	9	940,936,778
2005	10	989,774,274
2006	11	1,005,212,709
2007	12	1,015,287,553

PREDICTED	Year	t	
	2008	13	1,030,191,000
	2009	14	1,045,368,000
	2010	15	1,060,545,000
	2011	16	1,075,722,000
	2012	17	1,090,899,000
	2013	18	1,106,076,000

INTERCEPT	832,891,317.56
SLOPE	15,176,906.98



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.950271341
R Square	0.903015622
Adjusted R Square	0.893317185
Standard Error	16808516.86
Observations	12

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3.29384E+16	3.29384E+16	93.1093898	2.20265E-06
Residual	10	3.5376E+15	3.5376E+14		
Total	11	3.6476E+16			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	832891317.6	11575841.92	71.95081994	6.55997E-15	807098734.5	858683900.6	807098734.5	858683900.6
X Variable 1	15176906.98	1572847.195	9.649320691	2.20265E-06	11672385.05	18681428.91	11672385.05	18681428.91

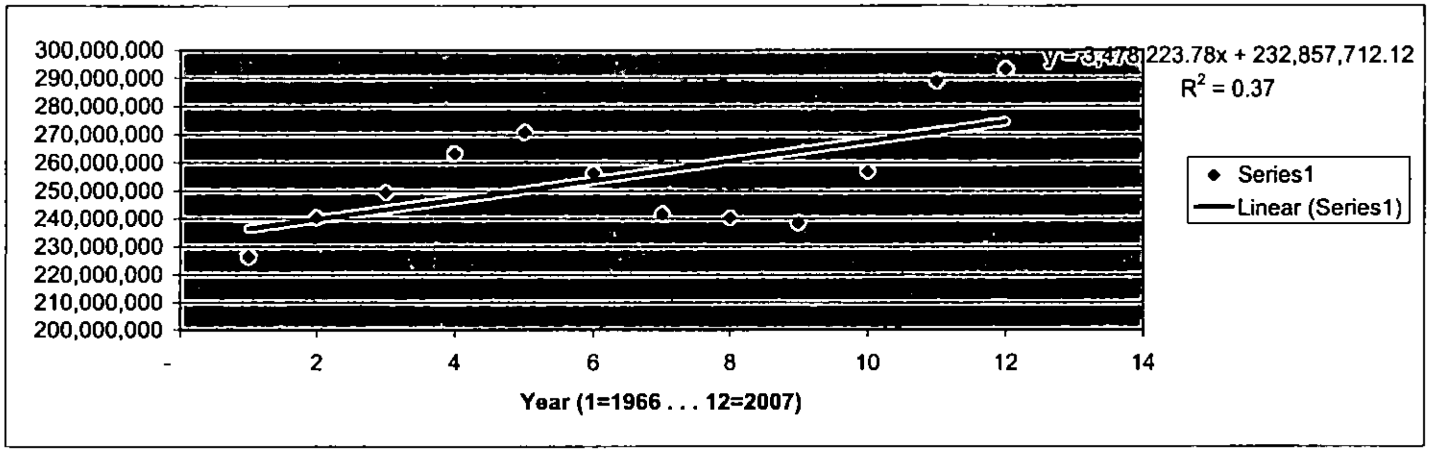
DOCKET NO. 2008-0274
ATTACHMENT 12A
PAGE 1 OF 1

HELCO [illegible]ress_wo major projects

	t	HELCO Avg Rate Base, less major projects net of dep, ADIT
1996	1	**226,319,000**
1997	2	**240,321,000**
1998	3	**249,447,000**
1999	4	**263,198,000**
2000	5	**270,798,000**
2001	6	**256,241,000**
2002	7	**241,576,000**
2003	8	**240,281,000**
2004	9	**238,459,000**
2005	10	**256,883,000**
2006	11	**288,876,000**
2007	12	**293,195,000**

PREDICTED	Year	t	
	2008	13	278,075,000
	2009	14	281,553,000
	2010	15	285,031,000
	2011	16	288,509,000
	2012	17	291,988,000
	2013	18	295,466,000

INTERCEPT	232,857,712.12
SLOPE	3,478,223.78



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.608970816
R Square	0.370845455
Adjusted R Square	0.307930001
Standard Error	17131986.63
Observations	12

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1.73002E+15	1.73002E+15	5.894345961	0.035582157
Residual	10	2.93505E+15	2.93505E+14		
Total	11	4.66507E+15			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	232857712.1	10544008.89	22.08436227	8.12544E-10	209364196.4	256351227.9	209364196.4	256351227.9
X Variable 1	3478223.776	1432648.694	2.427827416	0.035582157	286083.5738	6670363.979	286083.5738	6670363.979

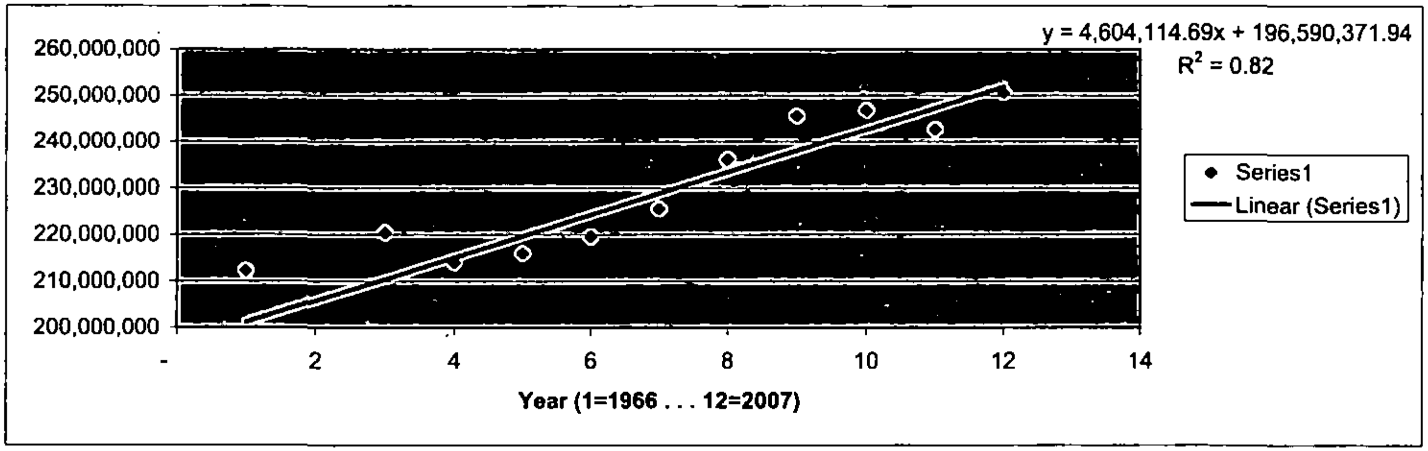
DOCKET NO. 2008-0274
ATTACHMENT 12B
PAGE 1 OF 1

MECO [illegible]ss_wo major projects

	t	MECO Avg Rate Base, less major projects net of dep, ADIT
1996	1	212,195,895
1997	2	188,961,589
1998	3	220,350,822
1999	4	213,910,215
2000	5	215,875,719
2001	6	219,485,726
2002	7	225,543,750
2003	8	236,134,987
2004	9	245,631,028
2005	10	246,828,569
2006	11	242,678,204
2007	12	250,608,908

PREDICTED	Year	t	
	2008	13	256,444,000
	2009	14	261,048,000
	2010	15	265,652,000
	2011	16	270,256,000
	2012	17	274,860,000
	2013	18	279,464,000

INTERCEPT	196,590,371.94
SLOPE	4,604,114.69



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.906594579
R Square	0.821913731
Adjusted R Square	0.804105105
Standard Error	8104313.856
Observations	12

ANOVA

	df	SS	MS	F	Significance F
Regression	1	3.0313E+15	3.0313E+15	46.15256065	4.7783E-05
Residual	10	6.56799E+14	6.56799E+13		
Total	11	3.68809E+15			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	196590371.9	4987860.379	39.41376803	2.64148E-12	185476726.5	207704017.4	185476726.5	207704017.4
X Variable 1	4604114.692	677716.7708	6.793567594	4.7783E-05	3094067.631	6114161.753	3094067.631	6114161.753

Confidential Information Deleted Pursuant To Protective Order, Filed on January 6, 2009.

DOCKET NO. 2008-0274
ATTACHMENTS 13A-13C

Attachments 13A, 13B, and 13C contain confidential information and are provided subject to the Protective Order filed on January 6, 2009 in this proceeding.

Significant Projects Methodology

(In $000s)

HECO Average Rate Base		2009	2010	2011
Average Rate Base - Base - 2009	N.1	$ 1,334,931	$ 1,334,931	$ 1,334,931
Rate Base Growth ($15,177K per year)	N.2	$ -	$ 15,177	$ 30,354
		$ 1,334,931	$ 1,350,108	$ 1,365,285
Significant Project Impact (Average)	N.3			
1/2 of CIP CT-1			$ 77,792	$ 74,826
EOTP (1/2 in 2010)			$ 8,399	$ 16,016
Total Average Rate Base		$ 1,334,931	$ 1,436,299	$ 1,456,127

HECO Average Rate Base (with full cost)		2009	2010	2011
Average Rate Base - Base - 2009	N.1	$ 1,334,931	$ 1,334,931	$ 1,334,931
Rate Base Growth ($15,177K per year)	N.2	$ -	$ 15,177	$ 30,354
		$ 1,334,931	$ 1,350,108	$ 1,365,285
Significant Project Impact (Full Cost)	N.3			
1/2 of CIP CT-1			$ 77,792	$ 74,826
Full cost of EOTP			$ 16,798	$ 16,016
Total Average Rate Base		$ 1,334,931	$ 1,444,698	$ 1,456,127

N.1 See "Rate Base Projection (Base Case with Significant Projects)" from D.Doi - 1/28/09

N.2 Rate Base Growth from regression for HECO ("HECO Rate Bases wo major projects") from K.Yamashita - 1/28/09

N.3 See Significant Projects - Forecast from K. Yamashita - 1/29/09

Significant Projects Methodology

(In $000s)

MECO Average Rate Base		2009	2010	2011	2012	2013
Average Rate Base - Base - 2009	N.1	$ 402,382	$ 402,382	$ 402,382	$ 402,382	$ 402,382
Rate Base Growth ($4,604K per year)	N.2	$ -	$ 4,604	$ 9,208	$ 13,812	$ 18,416
		$ 402,382	$ 406,986	$ 411,590	$ 416,194	$ 420,798
NO SIGNIFICANT PROJECTS						
Total Average Rate Base		$ 402,382	$ 406,986	$ 411,590	$ 416,194	$ 420,798

MECO Average Rate Base (with full cost)		2009	2010	2011	2012	2013
Average Rate Base - Base - 2009	N.1	$ 402,382	$ 402,382	$ 402,382	$ 402,382	$ 402,382
Rate Base Growth ($4,604K per year)	N.2	$ -	$ 4,604	$ 9,208	$ 13,812	$ 18,416
		$ 402,382	$ 406,986	$ 411,590	$ 416,194	$ 420,798
NO SIGNIFICANT PROJECTS						
Total Average Rate Base		$ 402,382	$ 406,986	$ 411,590	$ 416,194	$ 420,798

N.1 See "Rate Base Projection (Base Case with Significant Projects)" from L. Matsunaga - 1/28/09

N.2 Rate Base Growth from regression for HECO ("HECO Rate Bases wo major projects") from K.Yamashita - 1/28/09

Significant Projects Methodology

(In $000s)

HELCO Average Rate Base		2009	2010	2011	2012	2013
Average Rate Base - Base - 2009	N.1	$ 432,904	$ 432,904	$ 432,904	$ 432,904	$ 432,904
Rate Base Growth ($3,478 per year)	N.2	$ -	$ 3,478	$ 6,956	$ 10,434	$ 13,912
		$ 432,904	$ 436,382	$ 439,860	$ 443,338	$ 446,816
1/2 of ST-7			$ 43,783	$ 42,393	$ 41,002	$ 39,612
Total Average Rate Base		$ 432,904	$ 480,165	$ 482,253	$ 484,340	$ 486,428

HELCO Average Rate Base (with full cost)		2009	2010	2011	2012	2013
Average Rate Base - Base - 2009	N.1	$ 432,904	$ 432,904	$ 432,904	$ 432,904	$ 432,904
Rate Base Growth ($3,478 per year)	N.2	$ -	$ 3,478	$ 6,956	$ 10,434	$ 13,912
		$ 432,904	$ 436,382	$ 439,860	$ 443,338	$ 446,816
1/2 of ST-7			$ 43,783	$ 42,393	$ 41,002	$ 39,612
Total Average Rate Base		$ 432,904	$ 480,165	$ 482,253	$ 484,340	$ 486,428

N.1 See "Rate Base Projection (Base Case with Significant Projects)" from P. Franklin - 1/29/09
N.2 Rate Base Growth from regression for HECO ("HELCO Rate Bases wo major projects") from K.Yamashita - 1/28/09
N.3 See Significant Projects - Forecast from K. Yamashita - 1/29/09

Attachments 15A.1 through 15C.1 contain confidential information and are provided subject to the Protective Order filed on January 6, 2009 in this proceeding.

PRELIMINARY STATEMENT Sheet 1

AAA. Post Test Year Ratemaking Mechanism (PTYR)

1. Purpose

The Post Test Year Ratemaking (PTYR) mechanism shall provide SCE with additional authorized Distribution and Generation base revenues during 2007 and 2008 in accordance with D.06-05-016. (T) (T)

The PTYR mechanism consists of the following three elements: (T)

1. Operation and Maintenance (O&M) Expense Adjustment;
2. Capital Additions Adjustment; and (T)
3. Z-Factors Adjustment. (T)

2. Applicability

The PTYR mechanism is effective for calendar years 2007 and 2008, unless extended by Commission order. (T)

3. Definitions

a. Capital Additions

Post-test year capital additions are escalated as follows in accordance with D.06-05-016. The test year 2006 authorized gross additions of $1.623 billion are escalated by 2.5% for 2007 and 2.5% for 2008. The authorized gross additions for 2007 and 2008 shall be $1.664 billion and $1.705 billion respectively. (C) (I) (T) (C)

b. GRC Escalation Rate Methodology

The GRC Escalation Rate Methodology shall be used to implement 2007 and 2008 Operation and Maintenance (O&M) expense adjustments adopted in D.06-05-016 as follows: (T) (T)

(i) Labor and non-labor O&M expense adjustments shall be calculated using second quarter escalation factors issued by Global Insight Utility Cost Information Service (Global Insight);

(ii) Any forecast error in the O&M expense adjustment resulting from the difference between escalation factors using the second quarter Global Insight factor projections, and subsequent escalation rate projections shall not be recovered from, or returned to, SCE's customers;

(iii) 2007 medical program expenses including Post-Retirement Benefits Other Than Pensions (PBOPs) shall be calculated using a nine percent escalation rate adopted in D.06-05-016; (T) (T)

(iv) 2008 medical program expenses including PBOPs shall be calculated using a zero percent escalation rate adopted in D.06-05-016; and (T) (T)

(v) Union-represented labor expense adjustments shall be calculated using the provisions of labor contracts between SCE and its labor unions as adopted in, D.04-07-022 and D.06-05-016. (T)

(Continued)

AAA. Post Test Year Ratemaking Mechanism (PTYR) (Continued)

3. Definitions (Continued)

(D)

c. Z-Factor (T)

Z-Factors (Exogenous Cost Adjustments) are those events that result in a major cost impact to SCE.

d. Interest Rate (T)

The Interest Rate shall be one-twelfth of the Federal Reserve three-month Commercial Paper Rate – Non-Financial, from Federal Reserve Statistical Release H.15 (expressed as an annual rate). If in any month a non-financial rate is not published, SCE shall use the Federal Reserve three-month Commercial Paper Rate – Financial. (C)

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Southern California Edison
Rosemead, California

Revised Cal. PUC Sheet No. 40745-E
Cancelling Original Cal. PUC Sheet No. 36620-E

PRELIMINARY STATEMENT Sheet 3

(Continued)

AAA. Post Test Year Ratemaking Mechanism (PTYR) (Continued)

4. Establishment of PTYR Revenue Requirements

On November 1, of the Post Test Year, SCE shall file an advice letter with the Commission to implement updated Post Test Year revenue requirements. The updated Post Test Year revenue requirement shall be based on the following: (T) (T)

a. O&M expense escalation using the GRC Escalation Rate Methodology;

b. Capital costs based on capital additions methodology Capital Additions forecast approved in D.06-05-016; and (T) (T)

c. The expected number of SONGS 2&3 refueling and maintenance outages.

(D)

(Continued)

AAA. Post Test Year Ratemaking Mechanism (PTYR) (Continued)

(D)

5. Z-Factors:

Continuation of the Z-Factors methodology is authorized in D.06-05-016. In order to receive the ratemaking treatment provided for a Z-Factor, a Potential Z-Factor, must qualify as a Z-Factor under the criteria set forth in Decision No. 94-06-011: (T)

a. Identification of Potential Z-Factors:

A Potential Z-Factor may be identified by the Utility or the Office of Ratepayers Advocates (ORA). The Commission shall be notified of all Potential Z-Factors by a Letter of Notification in compliance with Decision No. 96-09-092. The Letter of Notification shall be sent to the Commission addressed to the Executive Director. For all Potential Z-Factors identified by the Utility, copies of the letter shall be sent to the Director of the Energy Division and the Director of the ORA. For all Potential Z-Factors identified by the ORA, copies of the Letter of Notification shall also be sent to the Senior Vice President of Regulatory Policy and Affairs and the Manager of the Revenue and Tariffs Division of the Utility. The Letter of Notification shall:

(1) clearly identify the Potential Z-Factor,

(2) include a detailed description of the event,

(3) include a forecast of the annual financial impact of the Potential Z-Factor; and

(4) show how the Potential Z-Factor meets the Z-Factor Criteria per D.94-06-011.

b. Application for Z-Factor Recovery: (L)

In order to receive recovery of a Z-Factor, the Utility shall include its request for recovery of the revenue requirement associated with the Potential Z-Factor in an Advice Filing.

c. Z-Factor Threshold:

The Utility will bear the risk of all potential Z-Factors which do not have a financial impact on the Utility of more than $10 million. The $10 million threshold amount is also applied as a deductible on a one-time basis to each Z-Factor authorized for recovery by the Commission. The deductible amount is only applied in the first year's ratemaking treatment for the Z-Factor. The $10 million deductible does not apply to the formation of new municipal utilities and for projects subject to Public Utilities Code Section 463 for which the Utility is seeking Z-Factor recovery. (L)

PRELIMINARY STATEMENT Sheet 5

(Continued)

AAA. Post Test Year Ratemaking Mechanism (PTYR) (Continued)

5. 2004-2005 Capital Additions Adjustment Mechanism (Continued)

d. Determining a Base Revenue Requirement Reduction Amount

3. The monthly revenue requirement balance shall be CPUC jurisdictionalized by applying the CPUC Jurisdictional Factor;

4. Monthly interest shall be added by applying the Interest Rate to the average of the beginning and ending monthly revenue requirement balances; and

5. The December 31, 2005 CPUC Jurisdictional revenue requirement balance (including interest) shall be functionalized .between Distribution and Generation using the applicable Functionalization Factors.

6. The Distribution-related revenue requirement shall be credited to the Distribution Sub-account of the BRRBA; the Generation-related revenue requirement shall be credited to the Generation Sub-account of the BRRBA.

e. Capital Additions Report for 2004-2005

By March 15, 2006, SCE shall submit an advice letter to the Commission that reports SCE's recorded Capital Additions for calendar years 2004 and 2005, and includes support for the calculation of a base revenue requirement reduction amount (if any). The advice letter will include all necessary information and supporting workpapers for the Commission to review and approve SCE's post-test year Capital Additions rate recovery.

6. SONGS 2&3 Refueling and Maintenance Outage Tracking Account

The SONGS 2&3 Refueling and Maintenance Outage Tracking Account (SONGS 2&3 RMOTA) shall track for each calendar year 2004 and 2005 the revenue requirement difference between: 1) the actual number of SONGS 2&3 refueling and maintenance outages; and 2) the number of SONGS 2&3 refueling and maintenance outages included in SCE's authorized generation revenue requirement. The account shall not track SONGS 2&3 unplanned outages.

D.04-07-022 authorizes SCE to recover $39.500 million (Constant 2000 Dollars, SCE's Share) for each SONGS 2&3 refueling and maintenance outage that actually occurs in 2004 and 2005 (i.e., a "flexible" nuclear refueling and maintenance outage schedule). SONGS 2&3 refueling and maintenance outage expenses to be included in SCE's authorized generation revenue requirements in 2004 and 2005 shall be determined using the second quarter Global Insight escalation factors.

(Continued)

AAA. Post Test Year Ratemaking Mechanism (PTYR) (Continued)

6. SONGS 2&3 Refueling and Maintenance Outage Tracking Account (Continued)

a. Actual Outages Equal Forecast Outages

If the actual number of SONGS 2&3 refueling and maintenance outages for 2004 and 2005 equal the number of SONGS 2&3 refueling and maintenance outages included in SCE's generation revenue requirement for 2004 and 2005, then no over-collection or under-collection calculation shall be necessary.

b. Actual Outages Less Than Forecast Outages

If the actual number of SONGS 2&3 refueling and maintenance outages in 2004 and/or 2005 is less than the number of refueling and maintenance outages reflected in SCE's 2004 and/or 2005 generation revenue requirement, then SCE shall have over-collected its SONGS 2&3 refueling and maintenance outage expenses for 2004 and/or 2005. The difference in the number of outages shall be multiplied by the authorized SONGS 2&3 refueling and maintenance outage expenses for 2004 and/or 2005 to derive an annual over-collection amount. Such amount shall be included in the operation of the SONGS 2&3 RMOTA.

SCE shall return a SONGS 2&3 refueling and maintenance outage expense over-collection for 2004 and/or 2005 through an advice filing submitted to the Commission by February 15th of 2005 (for 2004 over-collections) and/or 2006 (for 2005 over-collections). The advice filing shall include workpapers supporting all calculations. Upon Commission approval of SCE's February 15th advice filing, a SONGS 2&3 refueling and maintenance outage expense over-collection in 2004 and/or 2005 shall be returned to SCE's customers through a credit entry to the generation Sub-account of SCE's Base Revenue Requirement Balancing Account (BRRBA). The entry shall include accrued interest expense.

PRELIMINARY STATEMENT Sheet 7

(Continued)

AAA. Post Test Year Ratemaking Mechanism (PTYR) (Continued)

6. SONGS 2&3 Refueling and Maintenance Outage Tracking Account (Continued)

c. Actual Outages Greater Than Forecast Outages

If the actual number of SONGS 2&3 refueling and maintenance outages in 2004 and/or 2005 is greater than the number of SONGS 2&3 refueling and maintenance outages included in SCE's revenue requirements for 2004 and/or 2005, then SCE shall have under-collected its authorized SONGS 2&3 refueling and maintenance outage expenses for 2004 and/or 2005. The difference in the number of outages shall be multiplied by the authorized SONGS 2&3 refueling and maintenance outage expenses for 2004 and/or 2005 to derive an annual under-collection amount. Such amount shall be included in the operation of the SONGS 2&3 RMOTA.

SCE shall recover from customers a SONGS 2&3 refueling and maintenance outage expense under-collection for 2004 and/or 2005 through an advice filing submitted to the Commission by February 15th of 2005 (for 2004 under-collections) and/or 2006 (for 2005 under-collections). The advice filing shall include workpapers supporting all calculations. Upon Commission approval of SCE's February 15th advice filing, a SONGS 2&3 refueling and maintenance outage expense under-collection in 2004 and/or 2005 shall be recovered from SCE's customers through a debit entry to the generation Sub-account of the BRRBA. The entry shall include accrued interest expense.

d. Operation of the SONGS 2&3 RMOTA

Entries to the SONGS 2&3 RMOTA shall be made subsequent to December 31, 2004, and/or December 31, 2005, only if the conditions described above in b or c occur.

1. Monthly SONGS 2&3 refueling and maintenance outage expenses that should have been included in SCE's authorized generation base revenue requirement;

2. Less: Monthly SONGS 2&3 refueling and maintenance outage expenses that were included in SCE's authorized generation base revenue requirement.

If the above calculation is a positive amount (under-collection), such amount shall be debited to the SONGS 2&3 RMOTA. If the above calculation is a negative amount (over-collection), such amount shall be credited to the SONGS 2&3 RMOTA.

(Continued)

PRELIMINARY STATEMENT Sheet 8

(Continued)

AAA. Post Test Year Ratemaking Mechanism (PTYR) (Continued)

6. SONGS 2&3 Refueling and Maintenance Outage Tracking Account (Continued)

e. Interest Expense Calculation

Interest expense shall be applied to a 2004 and/or 2005 SONGS 2&3 refueling and maintenance outage expense over-collection or under-collection by applying the Interest Rate to the monthly difference between the SONGS 2&3 refueling and maintenance outage expense actually included in SCE's authorized generation revenue requirement, and the SONGS 2&3 refueling and maintenance outage expense that should have been included in SCE's authorized generation revenue requirement.

Interest expense shall be computed from January 1, 2004 and/or January 1, 2005, through the date of transfer to the generation Sub-account of the BRRBA.

7. Z-Factors:

Continuation of the Z-Factors methodology is authorized in D.04-07-022. In order to receive the ratemaking treatment provided for a Z-Factor, a Potential Z-Factor, must qualify as a Z-Factor under the criteria set forth in Decision No. 94-06-011:

a. Identification of Potential Z-Factors:

A Potential Z-Factor may be identified by the Utility or the Office of Ratepayers Advocates (ORA). The Commission shall be notified of all Potential Z-Factors by a Letter of Notification in compliance with Decision No. 96-09-092. The Letter of Notification shall be sent to the Commission addressed to the Executive Director. For all Potential Z-Factors identified by the Utility, copies of the letter shall be sent to the Director of the Energy Division and the Director of the ORA. For all Potential Z-Factors identified by the ORA, copies of the Letter of Notification shall also be sent to the Senior Vice President of Regulatory Policy and Affairs and the Manager of the Revenue and Tariffs Division of the Utility. The Letter of Notification shall:

(1) clearly identify the Potential Z-Factor,

(2) include a detailed description of the event,

(3) include a forecast of the annual financial impact of the Potential Z-Factor; and

(4) show how the Potential Z-Factor meets the Z-Factor Criteria per D.94-06-011.

(Continued)

PRELIMINARY STATEMENT Sheet 9

(Continued)

AAA. Post Test Year Ratemaking Mechanism (PTYR) (Continued)

7. Z-Factors:

b. Application for Z-Factor Recovery:

In order to receive recovery of a Z-Factor, the Utility shall include its request for recovery of the revenue requirement associated with the Potential Z-Factor in an Advice Filing.

c. Z-Factor Threshold:

The Utility will bear the risk of all potential Z-Factors which do not have a financial impact on the Utility of more than $10 million. The $10 million threshold amount is also applied as a deductible on a one-time basis to each Z-Factor authorized for recovery by the Commission. The deductible amount is only applied in the first year's ratemaking treatment for the Z-Factor. The $10 million deductible does not apply to the formation of new municipal utilities and for projects subject to Public Utilities Code Section 463 for which the Utility is seeking Z-Factor recovery.

(Continued)

SOUTHERN CALIFORNIA
EDISON
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Akbar Jazayeri
Vice President of Regulatory Operations

November 1, 2007

ADVICE 2176-E
(U 338-E)

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA
ENERGY DIVISION

SUBJECT: 2008 General Rate Case (GRC) Post Test Year Revenue Requirement in Accordance with Decision No.06-05-016

In accordance with Decision (D.) 06-05-016, Southern California Edison Company (SCE) hereby submits for filing the following changes to its tariff schedules. The revised tariff sheets are listed on Attachment A and are attached hereto.

PURPOSE

The purpose of this advice filing is to establish and implement GRC-authorized revenue requirements for the 2008 Post Test Year consistent with D.06-05-016.

BACKGROUND

On May 11, 2006, the Commission issued D.06-05-016 which, among other things, adopted a Post Test Year Ratemaking (PTYR) mechanism for SCE for the years 2007 and 2008. The adopted PTYR mechanism adjusts SCE's base-related revenue requirements[1] on an annual basis, in between GRC Test Years, to provide SCE with additional revenues to cover its costs of doing business.

The adopted PTYR mechanism includes the following elements:

- Implementation of Revenue Requirement Adjustments through Advice Filings;
- A Revenue Balancing Account to adjust for sales variations;[2]

1 SCE's base-related revenue requirements include the costs of operating, maintaining and investing in SCE's generation, distribution, and general functions, and exclude costs such as fuel and power procurement costs.

2 The Base Revenue Requirement Balancing Account (BRRBA) will continue to operate as the authorized base revenue balancing account during the 2008 Post Test Year. The BRRBA

- A "Z" Factor Mechanism to Address Major Exogenous Cost Changes; and
- Implementation of updated Post Test Year revenue requirements as follows:
  - An annual Operations and Maintenance (O&M) Expense Adjustment which uses forecast labor and non-labor escalation rates;
  - An annual Capital Additions Adjustment which uses the adopted annual capital additions escalation factor of 2.5 percent to escalate SCE's capital additions forecast approved in D.06-05-016; and
  - An annual SONGS 2&3 Refueling and Maintenance Outage Cost Adjustment.

IMPLEMENTATION OF 2008 GRC-AUTHORIZED REVENUE REQUIREMENTS

SCE's 2008 Post Test Year revenue requirement or Authorized Base Revenue Requirement (ABRR) is based on the following:

- Adjustment of O&M expenses based on (1) Global Insight Utility Cost Information Service's (Global Insight) 2007 second quarter labor and non-labor escalation factors applicable to non-represented employees; (2) the provisions of labor contracts between SCE and its labor unions applicable to represented employees; and (3) the adopted Medical Program Expense (including post-retirement benefits other than pensions) escalation factor of 0 percent – Appendix 1 to this advice letter includes the labor and non-labor escalation rates utilized for 2008.
- Adjustment of capital-related costs based on the annual capital additions escalation factor of 2.5 percent approved in D.06-05-016.
- Adjustment of generation costs to reflect one planned refueling outage at SONGS 2&3 – Appendix 2 to this advice letter includes the calculation of the 2008 SONGS 2 & 3 nuclear refueling outage revenue requirement.

SCE has calculated its 2008 ABRR using the current Commission-adopted 8.77 percent rate of return.[3] Table 1 below shows SCE's functionalized 2008 ABRR to be effective on January 1, 2008.[4] Beginning on January 1, 2008, SCE will recover this ABRR through the operation of the BRRBA. As discussed below, SCE will consolidate its

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compares, on a monthly basis, Commission-authorized base distribution and generation revenue requirements to the recorded retail distribution and generation revenues.

3 On May 8, 2007, SCE filed its 2008 Cost of Capital request, A.07-05-003, requesting a rate of return on rate base of 8.87 percent. SCE will supplement this advice letter when a decision is issued in A.07-05-003 adopting a new authorized rate of return on rate base.

4 SCE's 2008 ABRR does not include the effect of the Gain on Sale decisions, D.06-05-041 and D.06-12-043, since approval is still pending in Advice 2020-E-B filed on April 16, 2007.

January 1, 2008 ABRR in rate levels as part of the 2008 Energy Resource Recovery Account (ERRA) Forecast proceeding (A.07-08-004).

TABLE 1
2008 GRC Adopted Revenue Requirement - Functionalized
With One Refueling & Maintenance Outage
and Authorized Rate of Return at 8.77%
Thousands of Dollars

Line No.	Item	Distribution	Generation	Total
1.	**Base Revenues**	2,901,405	1,218,122	4,119,527
2.	**Expenses:**			
3.	Operation & Maintenance	1,159,999	714,533	1,874,532
4.	Depreciation	687,388	194,743	882,131
5.	Taxes	452,087	169,572	621,658
6.	Revenue Credits	(159,441)	(11,181)	(170,622)
7	Total Expenses	2,140,033	1,067,667	3,207,700
8.	**Net Operating Revenue**	761,372	150,455	911,827
9.	***Rate Base***	*8,681,546*	1,715,572	*10,397,119*
10.	**Rate of Return**	8.77%	8.77%	8.77%

PRELIMINARY STATEMENT MODIFICATIONS

This advice filing revises:

- Preliminary Statement, Part N, Section 8, Results Sharing Memorandum Account (RSMA) to reflect the authorized funding level included in SCE's 2008 ABRR;
- Preliminary Statement, Part X, Research, Development and Demonstration Adjustment Clause (RDDAC) to reflect the authorized funding level included in SCE's 2008 ABRR;
- Preliminary Statement, Part Y, Demand Response Programs Balancing Account (DRPBA) to reflect the GRC-authorized funding level included in SCE's 2008 ABRR;
- *Preliminary Statement, Part NN, Mohave Balancing Account (MBA) to reflect the* GRC-authorized Mohave revenue requirement included in SCE's 2008 ABRR;

- Preliminary Statement, Part YY, Base Revenue Requirement Balancing Account to reflect the January 1, 2008 ABRR which includes the Authorized Distribution Base Revenue Requirement and Authorized Generation Base Revenue Requirement set forth in this advice letter.[5]

RATE LEVEL CHANGE

Consistent with its proposal in A.07-08-004 (SCE's 2008 ERRA Forecast Proceeding), SCE will include its 2008 PTYR mechanism ABRR change set forth in this advice letter, in its consolidated rate change that will take place after receiving a decision in A.07-08-004.[6] Therefore, SCE's rates will not change as a result of implementing this advice letter filing.

TIER DESIGNATION

Pursuant to D.07-01-024, Energy Industry Rule 5.2, SCE submits this advice filing with a Tier 2 designation.

EFFECTIVE DATE

This advice filing is made in compliance with D.06-05-016. Therefore, this advice letter shall become effective on January 1, 2008.

NOTICE

Anyone wishing to protest this advice filing may do so by letter via U.S. Mail, facsimile, or electronically, any of which must be received no later than 20 days after the date of this advice filing. Protests should be mailed to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, California 94102
E-mail: jnj@cpuc.ca.gov and mas@cpuc.ca.gov

Copies should also be mailed to the attention of the Director, Energy Division, Room 4004 (same address above).

In addition, protests and all other correspondence regarding this advice letter should also be sent by letter and transmitted via facsimile or electronically to the attention of:

---

5 Consistent with the MDP Methodology included in Advice 1808-E, in order to more closely match the planned outage costs with the refueling outage revenue requirement, SCE has allocated the refueling outage revenue requirement by month using a forecast of when the outage is anticipated to occur. As such, the 2008 refueling outage revenue requirement is allocated evenly between October and November 2008. Refueling outage revenue requirements included in rate levels are subject to refund if a refueling outage does not occur – see Preliminary Statement YY, Section 6.

6 A Decision in A.07-08-004 is expected during the first quarter of 2008.

Akbar Jazayeri
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2244 Walnut Grove Avenue
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Facsimile: (626) 302-4829
E-mail: AdviceTariffManager@sce.com

Bruce Foster
Senior Vice President, Regulatory Affairs
c/o Karyn Gansecki
Southern California Edison Company
601 Van Ness Avenue, Suite 2040
San Francisco, California 94102
Facsimile: (415) 673-1116
E-mail: Karyn.Gansecki@sce.com

There are no restrictions on who may file a protest, but the protest shall set forth specifically the grounds upon which it is based and shall be submitted expeditiously.

In accordance with Section 4, of General Order No. 96-B, SCE is serving copies of this advice filing to the interested parties shown on the attached GO 96-B service list and A.04-12-014. Address change requests to the GO 96-B service list should be directed by electronic mail to AdviceTariffManager@sce.com or at (626) 302-4039. For changes to all other service lists, please contact the Commission's Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.

Further, in accordance with Public Utilities Code Section 491, notice to the public is hereby given by filing and keeping the advice filing at SCE's corporate headquarters. To view other SCE advice letters filed with the Commission, log on to SCE's web site at http://www.sce.com/AboutSCE/Regulatory/adviceletters.

For questions, please contact Kimwuana Kelley at (626) 302-4303 or by electronic mail at Kimwuana.Kelley@sce.com.

Southern California Edison Company

Akbar Jazayeri

AJ:kk:mm
Enclosures

CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING SUMMARY
ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Southern California Edison Company (U 338-E)

Utility type:	Contact Person: James Yee
☑ ELC ☐ GAS	Phone #: (626) 302-2509
☐ PLC ☐ HEAT ☐ WATER	E-mail: James.Yee@sce.com
	E-mail Disposition Notice to: AdviceTariffManager@sce.com

EXPLANATION OF UTILITY TYPE	(Date Filed/ Received Stamp by CPUC)
ELC = Electric GAS = Gas PLC = Pipeline HEAT = Heat WATER = Water	

Advice Letter (AL) #: 2176-E Tier Designation: 2

Subject of AL: 2008 General Rate Case (GRC) Post Test Year Revenue Requirement in Accordance with Decision No. 06-05-016

Keywords (choose from CPUC listing): Compliance, GRC

AL filing type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #:

D.06-05-016

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL:

Summarize differences between the AL and the prior withdrawn or rejected AL[1]:

Confidential treatment requested? ☐ Yes ☑ No If yes, please see the attached declaration for specific information.

Confidential information will be made available to those who execute a nondisclosure agreement.

Name and contact information to request nondisclosure agreement /access to confidential information:

Resolution Required? ☐ Yes ☑ No

Requested effective date: 1/1/08 No. of tariff sheets: 9

Estimated system annual revenue effect: (%):

Estimated system average rate effect (%):

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: Preliminary Statement Part (s) N, X, Y, NN, YY and Table of Contents

Service affected and changes proposed[1]:

Pending advice letters that revise the same tariff sheets: 2020-E-B

[1] Discuss in AL if more space is needed.

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Ave.,
San Francisco, CA 94102
jnj@cpuc.ca.gov and mas@cpuc.ca.gov

Akbar Jazayeri
Vice President of Regulatory Operations
Southern California Edison Company
2244 Walnut Grove Avenue
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Bruce Foster
Senior Vice President, Regulatory Affairs
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Southern California Edison Company
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San Francisco, California 94102
Facsimile: (415) 673-1116
E-mail: Karyn.Gansecki@sce.com

Appendix 1

O&M LABOR ESCALATION, 2008 INCORPORATING 2007 UPDATE

	2008 Incorporating 2007 Update	GI 2006Q2 Forecast	GI 2007Q2 Forecast	
	2008	2007	2007	2008
Steam				
% Change	3.23%	3.80%	3.68%	3.35%
Nuclear				
% Change	3.23%	3.80%	3.68%	3.35%
Hydro				
% Change	3.23%	3.80%	3.68%	3.35%
Other Power Prod.				
% Change	3.23%	3.80%	3.68%	3.35%
Transmission				
% Change	3.23%	3.80%	3.68%	3.35%
Distribution				
% Change	3.23%	3.80%	3.68%	3.35%
Customer Accounts				
% Change	3.23%	3.80%	3.68%	3.35%
CS&I				
% Change	3.23%	3.80%	3.68%	3.35%
A&G				
% Change	3.23%	3.80%	3.68%	3.35%

O&M NONLABOR ESCALATION, 2008 INCORPORATING 2007 UPDATE

	2008 Incorporating 2007 Update	GI 2006Q2 Forecast	GI 2007Q2 Forecast	
	2008	2007	2007	2008
Steam				
% Change	4.15%	1.69%	3.54%	2.30%
Four Corners				
% Change	3.76%	2.61%	3.60%	2.77%
Nuclear				
% Change	5.14%	2.17%	4.97%	2.33%
Palo Verde				
% Change	3.97%	3.16%	4.18%	2.95%
Hydro				
% Change	3.50%	1.86%	3.41%	1.95%
Other Power Prod.				
% Change	3.34%	2.75%	3.26%	2.83%
Transmission				
% Change	3.51%	2.54%	3.26%	2.79%
Distribution				
% Change	3.95%	2.25%	3.76%	2.44%
Customer Accounts				
% Change	2.58%	2.90%	2.85%	2.63%
CS&I				
% Change	3.26%	2.18%	3.13%	2.31%
A&G				
% Change	3.51%	3.67%	3.53%	3.64%

Appendix 2

2008 Post Test Year Ratemaking
SONGS 2&3 Refueling
(SCE Share Only)
Thousands of Dollars

1. Labor (2003$)		8,260
2. Nonlabor (2003$)		35,583
		43,843
3. Escalated		
4. Labor (2008$)		9,852
5. Nonlabor (2008$)		42,514
		52,366
6. Payroll Taxes, Results Sharing, etc.		975
	Total Per Refueling	53,341
7.	**Total Per Refueling w/FF&U**	**53,944**

Public Utilities Commission 2176-E Attachment A

Cal. P.U.C. Sheet No.	Title of Sheet	Cancelling Cal. P.U.C. Sheet No.
Revised 43146-E	Preliminary Statement Part N	Revised 42839-E
Revised 43147-E	Preliminary Statement Part X	Revised 41655-E
Revised 43148-E	Preliminary Statement Part Y	Revised 41656-E
Revised 43149-E*	Preliminary Statement Part NN	Revised 41657-E
Revised 43150-E	Preliminary Statement Part YY	Revised 41659-E
Revised 43151-E	Preliminary Statement Part YY	Revised 41660-E
Revised 43152-E	Preliminary Statement Part YY	Revised 41661-E
Revised 43153-E	Table of Contents	Revised 42643-E
Revised 43154-E	Table of Contents	Revised 42644-E

PRELIMINARY STATEMENT Sheet 9

(Continued)

N. MEMORANDUM ACCOUNTS (Continued)

8. Results Sharing Memorandum Account

The purpose of the Results Sharing Memorandum Account (RSMA) is to compare the authorized and actual Results Sharing expenses paid out for 2006, 2007 and 2008 and to record the difference pursuant to D.06-05-016 Ordering Paragraph 21.

a. SCE shall maintain the RSMA by making entries at the end of each month as follows:

1. A debit entry for the actual Results Sharing amount paid out;

2. A credit entry equal to the result of multiplying the authorized amount for Results Sharing by the applicable (Distribution / Generation) MDP as set forth in Preliminary Statement YY, Base Revenue Requirement Balancing Account (BRRBA).

Total Company Authorized – Results Sharing
In Thousands

	2003 Dollars	1/12/06 2006 Dollars	12/29/06 2006 Dollars	2003 Dollars	1/01/07 2007 Dollars	2008 Dollars
Generation	14,053	15,642	16,156	13,557	15,664	16,583(N)
Transmission & Distribution	29,280	32,592	32,592	29,280	33,831	34,924(N)
Customer Service	13,334	14,842	14,842	13,334	15,406	15,904(N)
Administrative & General	27,956	31,118	31,118	27,956	32,301	33,344(N)
Total	84,622	94,194	94,708	83,698	97,202	100,755(N)

Interest shall accrue monthly by applying one-twelfth of the Federal Reserve three-month Commercial Paper Rate – Non-Financial, from Federal Reserve Statistical Release H.15 (expressed as an annual rate) to the average monthly balance. If in any month a non-financial rate is not published, SCE shall use the Federal Reserve three-month Commercial Paper Rate – Financial.

Any underexpended CPUC Results Sharing balance, as recorded in the RSMA, shall be transferred to the BRRBA annually and reviewed in the annual April 1st ERRA reasonableness proceeding.

(Continued)

EDISON

Southern California Edison | Revised Cal. PUC Sheet No. 43147-E
Rosemead, California (U 338-E) | Cancelling Revised Cal. PUC Sheet No. 41655-E

PRELIMINARY STATEMENT Sheet 1

X Research, Development and Demonstration Adjustment Clause (RDDAC)

1. Purpose:

The purpose of the Research, Development and Demonstration Adjustment Clause (RDDAC) is to record the difference between: (1) the authorized expenditures associated with Research, Development and Demonstration (RD&D) programs reflected in the Authorized RD&D Funding Level; and (2) the recorded expenditures associated with RD&D programs.

2. Definitions.

a. Authorized Funding Level:

The Authorized Funding Level for RD&D programs is the amount authorized by the Commission to be reflected in Distribution rates. Such amount shall exclude Franchise Fees and Uncollectible Accounts (FF&U). The post test year amounts shall be determined in the Post Test Year Ratemaking advice letters submitted annually to the Commission by November 1.

Effective Date	($000) Authorized Level	
May 22, 2003	$1,573	
January 1, 2004	$1,602	
January 1, 2005	$1,658	
January 12, 2006	$1,768	
January 1, 2007	$1,808	
January 1, 2008	$1,879	(N)

b. Franchise Fees and Uncollectible Accounts:

Franchise Fees and Uncollectible Accounts shall be the rate derived from the Utility's most recent general rate case decision to provide for franchise fees and uncollectible accounts expense.

c. Interest Rate:

The Interest Rate shall be the most recent annual Federal Reserve three-month Commercial Paper Rate – Non-Financial, from Federal Reserve Statistical Release H.15. If an annual non-financial rate is not published, SCE shall use the annual Federal Reserve three-month Commercial Paper Rate – Financial.

d. Monthly Distribution Percentages

The Monthly Distribution Percentages (MDPs) Applicable to the RD&D Authorized Funding Level shall be the Distribution MDPs included in Preliminary Statement YY-Base Revenue Requirement Balancing Account.

(Continued)

EDISON

Southern California Edison Revised Cal. PUC Sheet No. 43148-E
Rosemead, California (U 338-E) Cancelling Revised Cal. PUC Sheet No. 41656-E

PRELIMINARY STATEMENT Sheet 2

(Continued)

Y. Demand Response Program Balancing Account (DRPBA) (Continued)

2. Definitions. (Continued)

a. Authorized Annual DRP Funding Levels (Continued)

(2) Authorized in SCE's GRC Proceeding

SCE's GRC Revenue Requirement adopted by the Commission includes the following DRP-related distribution revenue requirements associated with the Air Conditioning Cycling Program (ACCP), Agriculture & Pumping - Interruptible Program (AP-I), and Demand Bidding Programs (DBP):

	Authorized Distribution Funding Levels ($000)				
Year	1/1/06	1/12/06	2007	2008	
ACCP	3,274	5,308	5,842	6,032	(N)
AP-I		229	237	245	|
DBP		424	455	470	|
Total	3,274	5,961	6,534	6,747	(N)

b. Effective Date

The Effective Date of the DRPBA is January 1, 2006.

c. Interest Rate

The Interest Rate shall be the most recent annual Federal Reserve three-month Commercial Paper Rate – Non-Financial, from Federal Reserve Statistical Release H.15. If an annual non-financial rate is not published, SCE shall use the annual Federal Reserve three-month Commercial Paper Rate – Financial.

d. Monthly Distribution Percentages

The Monthly Distribution Percentages (MDPS) applicable to the DRP authorized funding levels shall be the applicable distribution MDPS or generation MDPS included in the Preliminary Statement YY – Base Revenue Requirement Balancing Account.

(Continued)

(To be inserted by utility)
Advice 2176-E
Decision 06-05-016

Issued by
Akbar Jazayeri
Vice President

(To be inserted by Cal. PUC)
Date Filed Nov 1, 2007
Effective Jan 1, 2008
Resolution

PRELIMINARY STATEMENT Sheet 1

NN. Mohave Balancing Account

1. Purpose:

The purpose of the Mohave Balancing Account (MBA) is to track the difference between: (1) recorded Capital-related Expenses, Operating Expenses and Worker Protection Expenses associated with the Mohave Generating Station (Mohave); and (2) the Authorized Mohave Revenue Requirement as adopted in D.06-05-016.

2. Definitions:

a. Authorized Mohave Revenue Requirement

The authorized Mohave Revenue Requirement is the amount adopted by the Commission in D.06-05-016. The post test year revenue requirement amounts shall be set forth in the Post Test Year Ratemaking advice letters submitted annually to the Commission by November 1.

Effective Date	Authorized Revenue Requirement $000	
1/12/06	$57,249	
1/01/07	$42,340	
1/01/08	$43,650	(N)

b. Capital-related Expenses

For purposes of making monthly entries to the MBA, capital-related expenses include: (1) depreciation expense based on the currently adopted depreciation rates; (2) return based on the currently authorized rate of return on rate base; and (3) taxes based on income, including appropriate income tax-related adjustments, and deferred income tax expense. Initially, Capital-related expenses are calculated based on the net investment at December 31, 2005.

c. Interest Rate

The Interest Rate shall be one-twelfth of the Federal Reserve three-month Commercial Paper Rate – Non-Financial, from Federal Reserve Statistical Release H.15 (expressed as an annual rate). If in any month a non-financial rate is not published, SCE shall use the Federal Reserve three-month Commercial Paper Rate – Financial.

d. Monthly Distribution Percentages

The Monthly Distribution Percentages (MDPs) applicable to the MBA authorized funding levels shall be the generation MDPs included in Preliminary Statement YY, Base Revenue Requirement Balancing Account (BRRBA).

e. Operating Expenses

For purposes of making monthly entries to the MBA, Mohave-related Operating Expenses include:

(1) SCE's share of Operation and Maintenance expenses (excl. fuel and fuel-related costs recorded in ERRA);[1/]

1/ Results Sharing is excluded because it will be recorded in a separate memorandum account established pursuant to D.06-05-016.

(Continued)

PRELIMINARY STATEMENT Sheet 1

YY. Base Revenue Requirement Balancing Account (BRRBA)

1. Purpose:

The purpose of the Base Revenue Requirement Balancing Account (BRRBA) is to record: 1) the difference between SCE's authorized distribution and generation base revenue requirements and recorded revenues from authorized distribution and generation rates; and 2) record other authorized and recorded costs authorized by the Commission. The BRRBA is established in accordance with D.04-07-022, and as modified by D.06-05-016.

2. Definitions:

a. Authorized Distribution Base Revenue Requirement:

The Authorized Distribution Base Revenue Requirement (ADBRR) is the most current Commission-authorized Distribution-related base revenue requirement. The current ADBRR is listed below:

Table A
Authorized Distribution Base Revenue Requirement
($000)

Effective Date	ADBRR
May 22, 2003	$ 2,432,380
January 1, 2004	$ 2,665,448
January 1, 2005	$ 2,770,383
January 1, 2006	$ 2,749,569
January 12, 2006	$ 2,611,710
December 29, 2006	$ 2,613,277
January 1, 2007	$ 2,763,065
January 1, 2008	$ 2,901,405 (N)

b. Authorized Generation Base Revenue Requirement:

The Authorized Generation Base Revenue Requirement (AGBRR) is the most current Commission-authorized Generation-related base revenue requirement. The current AGBRR is listed below:

Table B
Authorized Generation Base Revenue Requirement
($000)

Effective Date	AGBRR
May 22, 2003	$ 401,149
January 1, 2004	$ 675,852
September 7, 2004	$ 671,712
January 1, 2005	$ 596,049
January 1, 2006	$ 683,082
January 12, 2006	$ 1,137,582
December 29, 2006	$ 1,153,030
January 1, 2007	$ 1,152,135
January 1, 2008	$ 1,218,122 (N)

(Continued)

EDISON

Southern California Edison | Revised | Cal. PUC Sheet No. 43151-E
Rosemead, California (U 338-E) | Cancelling Revised | Cal. PUC Sheet No. 41660-E

PRELIMINARY STATEMENT — Sheet 2

(Continued)

YY. Base Revenue Requirement Balancing Account (BRRBA) (Continued)

2. Definitions: (Continued)

b. *Authorized Generation Base Revenue Requirement: (Continued)*

Table C
SONGS Refueling Amounts Included in AGBRR
($000)

Effective Date	AGBRR Without Refueling	Number of Refuelings included in AGBRR	Total Amount of Refuelings included in AGBRR	AGBRR	
May 22, 2003	$ 401,149	0	$ 0	$ 401,149	
January 1, 2004	$ 588,690	2	$ 87,162	$ 675,852	
September 7, 2004	*$ 584,550*	*2*	*$ 87,162*	*$ 671,712*	
January 1, 2005	$ 596,049	0	$ 0	$ 596,049	
January 1, 2006	$ 593,185	2	$ 89,897	$ 683,082	
January 12, 2006	$ 1,040,806	2	$ 96,776	$ 1,137,582	
December 29, 2006	$ 1,051,786	2	$ 101,244	$ 1,153,030	
January 1, 2007	$ 1,100,548	1	$ 51,587	$ 1,152,135	
January 1, 2008	$ 1,164,178	1	$ 53,944	$ 1,218,122	(N)

c. BRRBA Distribution Revenue:

1. BRRBA Billed Distribution Revenue:

Total recorded billed Distribution revenues, adjusted to remove the CARE discount,

2. Plus: the change (plus or minus) in the amount of BRRBA unbilled Distribution revenue (the reversal of prior month's estimated unbilled revenue, plus the current month's estimate);

3. Less: a provision for FF&U.

d. Franchise Fees (FF) Factor:

The current Commission FF factor adopted in SCE's most recent General Rate Case (GRC) to provide recovery for Franchise Fees.

GRC Decision	Factor
D.04-07-022	0.00847
D.06-05-016	0.00893

e. Uncollectible (U) Accounts Factor:

The current Commission U factor adopted in SCE's most recent General Rate Case (GRC) to provide recovery for Uncollectible expense.

GRC Decision	Factor
D.04-07-022	0.00324
D.06-05-016	0.00225

(Continued)

PRELIMINARY STATEMENT — Sheet 5

(Continued)

YY. Base Revenue Requirement Balancing Account (BRRBA) (Continued)

2. Definitions: (Continued)

j. Monthly Distribution Percentages (MDPs) (Continued)

2. Generation MDPs (Continued)

Applied to Authorized Refuelings

	In 2004	In 2005	In 2006	In 2007	In 2008	(N)
January	0.00%	0.00%	25.00%	0.00%	0.00%	|
February	25.00%	0.00%	25.00%	0.00%	0.00%	|
March	25.00%	0.00%	0.00%	0.00%	0.00%	|
April	0.00%	0.00%	0.00%	0.00%	0.00%	|
May	0.00%	0.00%	0.00%	0.00%	0.00%	|
June	0.00%	0.00%	0.00%	0.00%	0.00%	|
July	0.00%	0.00%	0.00%	0.00%	0.00%	|
August	0.00%	0.00%	0.00%	0.00%	0.00%	|
September	0.00%	0.00%	0.00%	0.00%	0.00%	|
October	25.00%	0.00%	25.00%	0.00%	50.00%	|
November	25.00%	0.00%	25.00%	50.00%	50.00%	|
December	0.00%	0.00%	0.00%	50.00%	0.00%	|
Total	100.00%	0.00%	100.00%	100.00%	100.00%	(N)

k. BRRBA Distribution and Generation Unbilled Revenues

Unbilled Revenues are accrued ("earned" revenue for financial statement purposes) BRRBA revenues associated with electric customer kWh usage that has not yet been billed by SCE.

(Continued)

SOUTHERN CALIFORNIA EDISON

Southern California Edison — Revised Cal. PUC Sheet No. 43153-E
Rosemead, California (U 338-E) — Cancelling Revised Cal. PUC Sheet No. 42643-E

TABLE OF CONTENTS — Sheet 1

Cal. P.U.C. Sheet No.

(Continued)

(To be inserted by utility)	Issued by	(To be inserted by Cal. PUC)
Advice 2176-E	Akbar Jazayeri	Date Filed Nov 1, 2007
Decision 06-05-016	Vice President	Effective Jan 1, 2008
1H8		Resolution

EDISON

Southern California Edison — Revised — Cal. PUC Sheet No. 43154-E
Rosemead, California (U 338-E) — Cancelling Revised — Cal. PUC Sheet No. 42644-E

TABLE OF CONTENTS — Sheet 2

(Continued)

Cal. P.U.C. Sheet No.

(Continued)

(To be inserted by utility)
Advice 2176-E
Decision 06-05-016

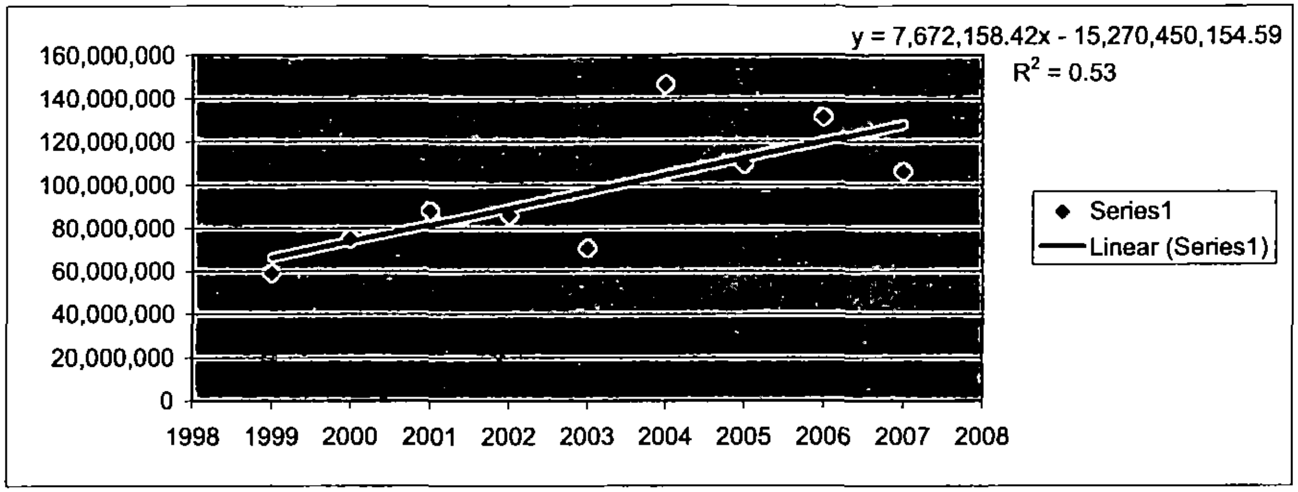
Issued by
Akbar Jazayeri
Vice President

(To be inserted by Cal. PUC)
Date Filed Nov 1, 2007
Effective Jan 1, 2008
Resolution

2C8

HECO Plant Adds Regression

	HECO Plant Additions $
1999	58,897,771
2000	75,025,801
2001	87,958,639
2002	86,213,894
2003	70,612,725
2004	146,577,115
2005	109,529,899
2006	131,037,917
2007	106,094,625



HECO

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.726841905
R Square	0.528299155
Adjusted R Sq	0.46091332
Standard Erroi	21224503.31
Observations	9

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3.53172E+15	3.53172E+15	7.839914063	0.026524836
Residual	7	3.15336E+15	4.5048E+14		
Total	8	6.68508E+15			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-15270450155	5488367964	-2.782329875	0.027206876	-28248378142	-2292522168	-28248378142	-2292522168
X Variable 1	7672158.417	2740071.595	2.799984654	0.026524836	1192918.674	14151398.16	1192918.674	14151398.16

CERTIFICATE OF SERVICE

I hereby certify that I have on this date served copies of the foregoing Revenue Decoupling Proposal and transmittal letter with this certificate of service by hand delivery or e-mail, as indicated below to the following:

CATHERINE P. AWAKUNI (2 copies by hand delivery and by e-mail)
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